NATIONAL RENEWABLE ENERGY LABORATORY

Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar

L. Bird, J. McLaren, and J. Heeter
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C. Linvill, J. Shenot, R. Sedano, and J. Migden-Ostrander
Regulatory Assistance Project (RAP)

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

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Technical Report
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November 2013

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NREL and RAP hosted a workshop, *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar*, on July 19, 2013. The workshop was designed to encourage dialog among stakeholders. This report summarizes key elements of the dialog but does not represent specific or consensus views of workshop participants, nor should it be construed as providing recommendations by participants or their institutions. Participants represented a broad range of perspectives, including public utility commissions, state energy offices, investor-owned and municipal utilities, the solar industry, non-profit organizations, and consulting firms. We would like to thank all of the workshop attendees for their thoughtful participation:

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Executive Summary

Consumer interest in and deployment of solar photovoltaics (PV) has accelerated in recent years. Increased adoption of distributed generation, particularly distributed solar PV, is expected to have impacts on utility-customer interactions, utility system cost recovery, and utility revenue streams. As a greater number of electricity customers choose to generate their own power, demand for utility system power declines. As a result, fixed system costs, such as the costs of transmission and distribution services, will be recovered over fewer kilowatt-hour (kWh) sales by the utility, and this could put upward pressure on electricity rates.

Regulators are facing the challenge of defining and preparing for the potential rate and revenue impacts from expansion of distributed PV. Looking forward, it will be important to address potential financial impacts on utilities that are responsible for ensuring that the electricity infrastructure supports reliable electric service for customers. The regulatory context and rate structures governing utilities and owners of residential and commercial-scale distributed PV present both market opportunities and market barriers that will influence the path forward for the incorporation of higher penetrations of distributed PV.

A number of regulatory models and rate design alternatives are available to address the challenges posed by the transition toward increased adoption of distributed PV. This paper is intended to help regulators:

- Understand the sources of costs and benefits from increased adoption of distributed PV
- Understand how regulatory models indicate different roles and value propositions for consumers, utilities, and non-utility electricity service providers
- Understand how rate design alternatives affect the value proposition for PV adopters, non-adopters, and utilities
- Frame the discussion with utilities, non-utility participants, and customers as they formulate equitable regulatory and rate design solutions.

Costs and Benefits

Distributed PV benefits system owners, utilities, the power system, and society in a variety of ways, including through the provision of energy and capacity, transmission and distribution system deferrals, line loss savings, fuel cost hedging, and environmental and health benefits. The costs include those associated with equipment, operations and maintenance (O&M), program administration, interconnection, and integration of the distributed systems. The magnitude of the costs and benefits of distributed PV vary according to the level of penetration, the local grid characteristics, and the coincidence of the solar electric production with the peak demand in the region. Assessments of costs and benefits have varied widely, and in some cases there is a lack of consensus regarding appropriate methodologies for assessing them.

Understanding the costs and benefits of distributed PV is essential to creating appropriate rate structures. The benefits and costs of distributed resources play into the consideration of ratepayer equity and rate design, especially at increased levels of adoption.

Business Models

The expansion of distributed PV creates the potential for new business models to emerge. Growth in the PV industry has already given rise to new solar business models, such as solar leasing, often administered by third-party entities. Distributed PV has been viewed by some as a threat to utility business models that profit from increased kWh sales. A few utilities are exploring new business opportunities to increase their participation and role in the deployment of distributed solar. Potential models for utility participation include customer demand aggregation, utility turnkey operations, utility-led community solar projects, partnership and investment in third-party leasing, value-added consulting services, and as a virtual power plant operator.

The impact of distributed PV on utility revenues depends on the role the utility will play in distributed energy resource expansion. Key considerations for regulators include the regulatory changes necessary to enable new business models and the potential implications on competition, reliability, and market access. Regulators may need to consider the balance between the role of utilities and the dynamic benefits of a third-party service provider sector.

Ratemaking Options

With expanding levels of distributed PV, new rate structures and regulatory policies may need to be considered. One issue will be to ensure that the utility collects sufficient revenue to cover its requirements and continue to safely and reliably provide vital services to all customers. Another key challenge will be to address equity across ratepayers and fairness for the utility and the distributed generator. Regulators will be challenged to design rates that compensate distributed PV customers for the net value they provide to the system while also requiring them to pay the full cost of the services they use. The solutions adopted will vary according to the state and locality and whether the utility is vertically integrated or operating in a state with a restructured electricity market.

Options for addressing revenue issues related to expanded adoption of PV include a variety of traditional ratemaking elements such as fixed monthly customer charges, demand charges, standby-rates, and time-based pricing. Other emerging options are two-way rates, such as value of solar tariffs, disaggregated rates, or the development of a separate customer class for PV customers. For rate designs that do not address issues associated with declining utility revenues, supplemental policies like decoupling or performance incentives can be applied to address the utility disincentive to support distributed solar or motivate utility participation. Regulators may seek to use a combination of tools to meet the needs of stakeholders.

Questions for Framing the Regulatory Discussion

Regulators who face issues associated with the expanded adoption of distributed PV will need to address them within the context of their state. The rate of PV deployment varies today by location and will likely continue to vary based on solar insolation, electricity rates, policies, and the regulatory context of the particular state. Regardless of these differences, a common set of questions may be useful for exploring and equitably addressing issues related to higher penetrations of distributed PV. These include developing an understanding of expected future adoption rates, the ability to address any needed system upgrades, impacts on various stakeholders, the possibility of stranded assets, and lessons that may be gleaned from other jurisdictions.

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1 Introduction

Improvements in distributed energy resources and demand-side automation technologies are fundamentally changing the electricity industry. Consumers, utilities, distributed generation companies, and third-party electricity service providers are each affected by the technological changes, and actions by utility regulators will affect how the respective roles will evolve over time. If regulation, policy, and utility planning are done well, the electric industry can reinforce a virtuous cycle of improvement that can improve cost, quality, and reliability of service. This report focuses on one aspect of distribution system change—the rapid adoption of distributed solar photovoltaics (PV)—and explores how rapid PV adoption interacts with different regulatory and rate design treatments to affect utility-customer interactions, system costs recovery, and utility revenue streams.

Defining and addressing the impacts of high PV adoption on utilities is important because supporting innovation, while maintaining a reliable and safe electricity infrastructure, requires the fair opportunity to recover utility costs. Defining and addressing the impacts on consumers, solar energy companies, and third-party electricity service providers are also important because innovation is encouraged by a business environment where companies can offer service options and consumers are free to respond based on value of service. A fair regulatory context and equitable rate structures could encourage utilities to enable the cost-effective adoption of distributed PV and discourage the creation of new barriers. In addition, effective regulation should ensure that core utility functions and service reliability are maintained with increasing amounts of distributed generation.

While PV provides less than 1% of total electricity generation in the United States today, deployment of PV is growing rapidly (EIA 2013). Installed PV capacity in the United States has more than tripled in the past three years. Installed costs for residential and commercial systems have declined rapidly, falling by about 30% over the last three years (GTM Research; SEIA 2013). If the cost of solar continues to decline and electricity rates continue to increase, distributed solar will offer an increasingly appealing value proposition for electricity consumers.

If a greater number of electricity customers choose to self-generate electricity, demand for system power will decrease and utility fixed costs will be recovered over fewer kilowatt-hours (kWh) of sales (Kind 2013). The consequence could be increased rates for those consumers who choose not to adopt PV and an inequitable shifting of costs from distributed generation (DG) owners to other customers (Vermont Public Service 2012; Navigant 2012; Vermont Public Service 2013; Crossborder Energy 2013; CPUC 2013). A rapid shift to high penetrations of distributed PV could create conflict among distributed PV users and other electric system ratepayers. The particular rate design employed plays an important role in whether—and the extent to which—cross-subsidization occurs. In addition, some utilities are concerned that certain rate designs fail to recognize the value of services provided by utilities to PV adopters and thus the rate charged to PV adopters may be unfairly low.

Regulators may need to address this rate design challenge in the near term. Part of the challenge that regulators face is determining the value and cost of additional distributed PV and the appropriate allocation of the costs and benefits among consumers. While distributed PV directly benefits PV system owners, it also offers a number of benefits to utilities, non-adopting consumers, the electric power system, and society. These benefits include potential transmission and distribution (T&D) network deferrals, provision of peak power, reduced line losses, fuel savings, and reduced emissions, among others. Distributed PV may also pose some costs to the system, such as administrative costs for interconnection and costs for modifications to address and potentially allow higher penetrations of distributed solar on the distribution system (Bradford and Hoskins 2013). The relative size of these costs and benefits is often location-dependent. These benefits and costs play into the consideration of ratepayer equity and rate design.

Improved PV economics and performance has been accompanied by innovation in utility and non-utility business models. Growth in the PV industry has already led to the creation of new solar business models, namely solar leasing, which eliminates the upfront cost barrier to consumers. A few utilities are also exploring new business opportunities, such as making investments in third-party leasing companies or making direct investments in solar. The changing landscape could induce a shift to other less familiar utility business models such as the utility service model described in Section 4. The potential for new business models has implications for regulation and rate structures that ensure equitable solutions for all electricity grid users. Regulators play a key role in enabling new business models and determining whether utilities are able to recover the cost of investments in distributed PV. The options vary based upon whether the utility is vertically integrated or operating in a restructured state.

This report examines considerations for regulators associated with expanded adoption of distributed PV. This report was informed by the discussion among utilities, regulators, and solar industry stakeholders at a workshop held in July 2013 designed to encourage dialog on this topic among stakeholders, but the report does not represent consensus of the workshop participants. Rather, it provides a synthesis of key issues associated with regulating distributed PV as it reaches higher penetrations.

Section 2 discusses the growth of distributed PV and the potential implications for financial impacts on system revenues. Section 3 provides an overview of the benefits and costs of PV and the implications for ratepayer equity. Section 4 discusses the potential for new and emerging business models that could support the expansion of distributed PV. Section 5 identifies regulatory tools and rate designs for addressing emerging issues with the expanded adoption of distributed PV and evaluates the potential effectiveness and viability of these options going forward. It offers the groundwork needed in order for regulators to explore mechanisms and ensure that utilities can collect sufficient revenues to provide reliable electric service, cover fixed costs, and balance cost equity among ratepayers—while creating a value proposition for customers to adopt distributed PV. The report concludes by providing regulators with important questions for framing the discussion and information that may be helpful to support a fair and equitable decision on distributed PV regulatory treatments and rate designs.

2 Distributed PV Growth and Potential Financial Implications

2.1 Potential Utility Impacts

Rapid growth of distributed PV in recent years has led to increased attention on utility system impacts, such as covering fixed system costs and ratepayer equity. This section discusses factors driving growth of distributed PV and affecting utility financial impacts.

Development of distributed solar has been driven in part by federal and state policies. At the federal level, the 30% investment tax credit for residential and commercial systems installed through 2016 is helping to reduce costs to the end user. At the state level, 29 states have renewable portfolio standards (RPS) that establish targets for increased generation of renewable electricity. Of these, 16 states plus Washington, D.C., have specific targets for solar or distributed energy, ranging from about 0.2% to 4% of retail electric sales, often by 2020 or 2025 (DSIRE 2013). In many states, utilities or other entities have implemented incentive programs, such as rebates or production incentives, to encourage the adoption of distributed PV to meet their RPS requirements or voluntary solar energy goals (Bird et al. 2012).

In addition to these policies, consumer interests in PV and technology cost reductions have contributed to accelerated deployment in recent years (see Figure 1). In 2012, a record 3,300 MW of PV was installed in the United States—more capacity than had been installed in the entire decade up to 2010—for a cumulative capacity of 7,219 MW (SEIA and GTM 2013). Distributed grid-connected PV has played a significant role in the expansion, increasing by 36% compared to 2011, to 1,600 MW_{DC} in 2012 (IREC 2013). While overall penetrations of PV remain very low relative to total energy capacity, deployment is being concentrated in a few states. In 2012, the leaders included California, Arizona, and New Jersey. Other leading states on a per-capita basis include Hawaii, Nevada, and New Mexico (IREC 2013) (see Figure 2). Also contributing to cost reductions is the fact that solar PV is expanding rapidly around the world; Germany (32 GW) and Italy (16 GW) were the global leaders in 2012 in terms of cumulative installed capacity (EPIA 2013).

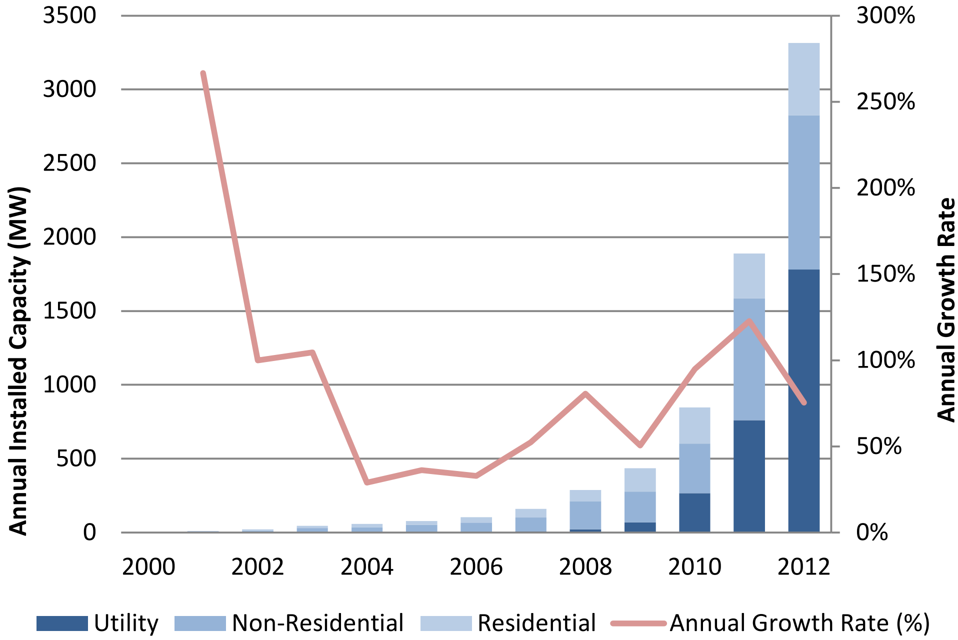


Figure 1. Annual PV capacity additions in the United States, 2000–2012

Source: SEIA/GTM Research 2010, 2013

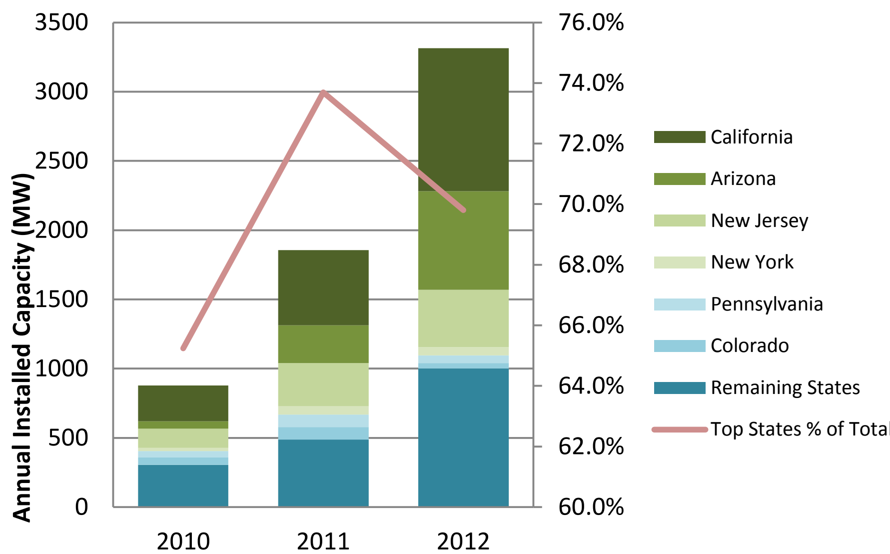


Figure 2. Annual installed PV capacity by state

Source: SEIA/GTM Research 2011, 2012, 2013

Installed prices of solar ($/watt) have declined rapidly, which is due in large part to reductions in module prices. From the second quarter of 2011 to the second quarter of 2012, residential system installed prices decreased by nearly 12% from $5.43/W to $4.81/W, while non-residential system prices decreased by nearly 15% from \$4.35/W to \$3.71/W (SEIA and GTM Research 2013). Internationally, installed prices have reached even lower levels, such as \$2.60/W in Germany and \$3.10/W in Italy for residential systems in 2012 (Barbose et al. 2013). According to a 2010 IEA report, solar should approach grid parity in many regions around the world by 2020 (Frankl et al. 2010), which could lead to substantial increases in installation rates. The U.S. Department of Energy's (DOE) SunShot initiative aims to reduce the cost of solar PV by 75% by 2020, equivalent to approximately \$1/W for utility-scale installations or \$0.06/kWh. Reaching this target would allow large solar systems to be competitive with traditional generating sources without subsidies (U.S. DOE 2011).

While distributed PV has the potential to continue to expand rapidly, it is not the only technology that could reduce utility retail sales. Efficiency measures and other DG sources also reduce electricity sales. The matter of declining revenues associated with energy efficiency has been recognized for some time, and a large body of research has examined potential solutions (see Moskovitz et al. 1992; National Action Plan for Energy Efficiency 2007; Lazar et al. 2011; RAP 2011). At the same time, there are some costs associated with distributed PV that are not experienced with energy efficiency, such as interconnection and integration costs (see Section 3). So, while the analogy with regard to lost sales is appropriate, it is widely acknowledged that there are some system costs associated with distributed PV that could affect utilities and are the subject of many discussions regarding if and how these should be accounted for.

Further, if storage technologies were to become more cost-competitive, customers could choose to leave the utility system entirely. The term "death spiral" has been used to describe a situation when customers leave the utility system and spread the fixed costs among a smaller number of customers. Such a situation would lead to higher prices for the remaining customers who in turn would have greater incentive to evaluate other options and potentially leave the system. A paper prepared for the Edison Electric Institute, the association of shareholder-owned electric companies, characterizes the concern as follows:

> The threat to the centralized utility service model is likely to come from new technologies or customer behavioral changes that reduce load. Any recovery paradigms that force cost of service to be spread over fewer units of sales (i.e., kilowatt-hours or kWh) enhance the ongoing competitive threat of disruptive alternatives...
>
> But even if cross-subsidies are removed from rate structures, customers are not precluded from leaving the system entirely if a more cost-competitive alternative is available (e.g., a scenario where efficient energy storage combined with distributed generation could create the ultimate risk to grid viability). While tariff restructuring can be used to mitigate lost revenues, the longer-term threat of fully exiting from the grid (or customers solely using the electric grid for backup purposes) raises the potential for irreparable damages to revenues and growth prospects (Kind 2013, p. 3).

While at first blush there may appear to be a negative impact on utility revenues associated with increased customer-sited PV, the impact on utility revenues depends on the role the utility will play in facilitating distributed energy resource expansion. The utility system impacts are determined by factors such as whether the utility shares ownership in customer-sited DG and the net effect on utility investments in generation and T&D infrastructure. The matter of utilities' roles involves an essential discussion about the role that third-party electric service providers will play; Section 4 is devoted to exploring the possible organizational structures of the industry.

2.2 Utility Financial Impact

Adding distributed PV to an electric system affects the utility in two basic ways:

1. Customer-sited DG reduces utility energy sales from central station generation.
2. DG in the generation portfolio affects required utility investment for other utility generation, and the need for infrastructure may increase or decrease.

While these effects appear to act together to negatively impact utility shareholders, they are not necessarily negative—they can also provide a net benefit. Furthermore, rate designs may or may not exacerbate electricity sale declines depending on whether rates reflect the value of service provided to customers. If the regulatory treatment and rate design reflects the value of service provided, then unintended cross-subsidization among customers can be minimized.

First, we can consider the impact of reduced energy sales. Reduced sales resulting from efficient customer-sited generation are akin to lost sales from cost-effective customer energy efficiency programs. Some utilities and utility commissions have found that decoupling is an effective mechanism for mitigating the lost revenues caused by cost-effective energy efficiency programs.

Decoupling is a well-known regulatory treatment to address the "throughput" problem faced by utilities. The "throughput" problem is that in non-decoupled cases, utilities profit from increased electricity sales. Decoupling can reduce lost revenues for shareholders and thus take away the disincentive that utilities may have when it comes to accommodating increased amounts of distributed PV on their system (see Section 5 for additional discussion of decoupling). The direct impact of decoupling on customer rates depends on how utility expenses change as distributed PV increases (e.g., how purchased power and fuel expense change).

In addition to the issue of reduced sales, increased use of distributed PV may negatively or positively affect utility investment opportunities. The *incremental* utility investment associated with increased customer-sited distributed PV may appear to be adverse, due to the reduced kilowatt-hour demand for electricity from utility generation. However, the *net* impact on utility investment depends on several variables, including: whether the utility shares any ownership in customer-sited PV; the effect of increased distributed PV on utility T&D investment; and any changes in utility generation associated with higher amounts of distributed PV in the electricity portfolio.

If the growth of customer-owned PV leads to a situation where the utility will have no investment opportunities, then shareholders may experience reduced profit. However, shared investment in distributed PV (e.g., utility investment in meters or inverters), incremental infrastructure expense (e.g., distribution system improvements or complementary firming resources), or some combination of shared investment and incremental infrastructure can make the shareholder as well off or potentially even better off. Utilities make a return from capital investment and they typically do not make a return on fuel expense. Thus, the fact that distributed PV is capital intensive without fuel expense can actually create opportunities for utility shareholders to benefit.

2.3 The Effect of Regulatory Treatment and Rate Design

The regulatory treatment of distributed PV varies by jurisdiction. Regulatory options include decoupling, net metering, feed-in tariffs, rate designs, and any restrictions placed on or permissions granted to utilities and third-party providers relative to their respective provision of DG services. The range of possibilities will be covered in Sections 4 and 5. The ultimate effect of any regulatory treatment or rate design is most frequently judged relative to its effectiveness in matching the marginal value of service provided with the marginal cost of that service.

If the marginal value of utility electric service provided to distributed PV adopters equals the marginal cost of providing that service, then traditional/rational economic theory tells us that the megawatts of distributed PV subscribed will be optimal. This simple principle is complicated by the fact that the value of distributed PV includes complex electric system effects as well as external benefits and costs that affect both the marginal benefit and marginal cost of a given level of PV adoption.

Basic economics tells us that setting the marginal cost of service for distributed PV adopters below the true cost will result in over-investment relative to the optimal level of investment. Over-investment affects utility shareholder profit between rate cases and affects utility investment opportunities over the long term. Between rate cases, over-investment in distributed PV exacerbates revenue reduction and thus leads to under-collection of fixed costs (for most rate designs) and under-performance of utility return on equity (if decoupling is absent). Over the longer term, over-investment affects utility long-term investment opportunities because over-investment leads to excess supply of generation, which reduces the value of future utility generation investment opportunities. Conversely, setting the marginal cost of service above the true cost will result in under-investment in distributed PV, which implies lost net benefits.

In regulated environments, the regulatory treatment and rate design will set the marginal cost of service for distributed PV adopters. Getting the treatment and design right is fundamental to ensuring maximum net benefits of distributed PV.

3 Benefits and Costs of Distributed PV

Regulators in most states have the experience of evaluating energy efficiency programs from the perspective of participants, non-participants, the administering utility, and society. While the benefits and costs of distributed PV include additional factors that are not included in energy efficiency evaluation, regulators may be well-positioned to identify the relevant benefits and costs and to evaluate how those benefits and costs affect stakeholders. As the penetration of distributed PV has increased, there has been more pressure to evaluate its costs and benefits, both from technical and ratemaking perspectives, and these evaluations are often the subject of controversy. Some argue that regulators need only to consider the costs incurred by the utility to manage distributed solar on the utility system. Others argue that regulators should consider broader impacts of distributed PV, including the potentially positive or negative ramifications that DG imparts to the utility system. In addition to determining the breadth of the costs and benefits to consider, regulators should be aware that the costs and benefits change in their degree of impact, depending on the amount of DG on any particular utility system.

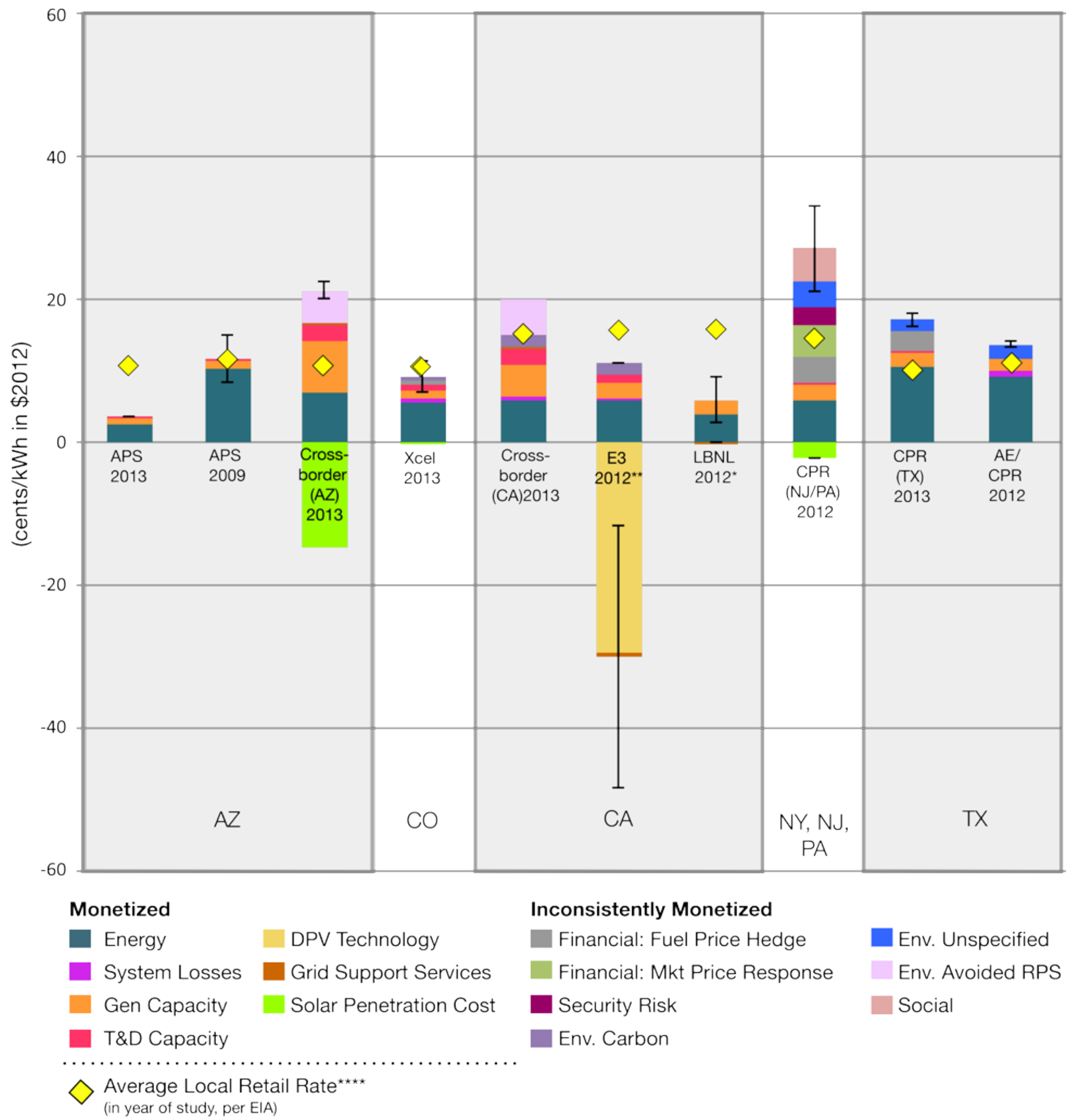
A number of studies on the benefits and costs of distributed PV are described in Hoke and Komor (2012), and quantitative estimates from a number of recent studies are cited below. In addition, Rocky Mountain Institute (RMI) has summarized recent studies examining PV costs and benefits from utility and advocate perspectives (RMI 2013).

This section summarizes the sources of distributed PV benefits and costs, presents recent estimates of them, and discusses how they accrue to the utility, PV system owners, or society.

3.1 Benefits of Distributed PV

As the penetration of distributed PV increases, there has been more pressure to evaluate its costs and benefits, particularly from a ratemaking perspective. Distributed PV provides a variety of environmental and economic benefits to the PV system owner, the electric utility, the utility ratepayers, and society as a whole. The PV system owner incurs the bulk of costs, but the utility may also incur administration, interconnection, and integration costs. As installed levels of distributed PV grow, it can become increasingly important for decision makers, particularly at the state and local level, to establish policies that consider the costs and benefits that accrue to all stakeholders.

The magnitude of the costs and benefits of distributed PV vary depending upon the level of PV penetration, the local grid characteristics, the coincidence of the solar electric production with the peak demand in the region, and other factors. There is substantial debate about methodologies for calculating the benefits and costs and the appropriate means of assigning them to various stakeholders. Recent studies conducted for specific utilities have calculated a relatively wide range of values. A recent publication by RMI provides a detailed overview of studies on the benefits and costs of DG (RMI 2013); Figure 3 presents the benefits and costs of distributed PV as stated in several utility- or state-specific studies between 2009 and 2013, demonstrating that the magnitude and type of benefits addressed vary by study. The y-axis shows the benefits of distributed PV in cents per kilowatt-hour; positive values indicate a benefit (e.g., energy and capacity), while negative values indicate a cost (e.g., technology cost).



* LBNL (2012) only provides the net value for ancillary services.

** The technology cost used by E3 includes the levelized cost of energy plus interconnection cost.

Figure 3. Benefits and costs of distributed PV by study

Source: Modified from RMI 2013

3.1.1 Generation Energy and Capacity Value

Distributed PV provides energy value when it produces kilowatt-hours that displace the need for generating energy using another generation source.[1] It provides capacity value when the distributed solar defers or avoids the need for other generating capacity. Deferral of new generation capital costs is more likely to occur by incorporating distributed PV into the grid operator's planning process (Hoke and Kumor 2012).

PV energy value can be estimated by looking at the avoided cost of either a utility's own fleet or the wholesale market. Differences in calculated energy values can be due to factors such as the market structure, the method of determining the marginal resource that is displaced, the fuel price forecast, and the period of the analysis. As can be seen in Figure 3, estimates of the energy value of PV are often in the range of $0.05/kWh to $0.10/kWh (RMI 2013).

The capacity value of PV is highly dependent upon the coincidence of distributed PV production with peak demand and its ability to contribute to system reliability, as well as its location in relation to load. LBNL (2012) found that in California, the capacity value of PV is expected to decline as PV penetration increases and the daily load shape changes. At the circuit level, distributed PV may or may not provide benefits, depending on the shape of circuit load. Studies have typically found the capacity value benefit ranging from zero to $0.10/kWh, with a number of estimates within the $0.01/kWh to $0.02/kWh range (APS 2009; NREL 2008). Studies conducted in earlier years that assumed higher natural gas and wholesale energy prices than are prevalent today likely have higher estimates of this value than those assuming lower prices.

Together, the energy and capacity value typically accounts for the largest component of the benefits of distributed PV and can be highly disputed, with studies reaching different values based on varying assumptions. There is no standard methodology for evaluating these benefits, though IREC and Rábago Energy have called for increased standardization in how to calculate these benefits (IREC 2013). IREC and Rábago Energy (2013) suggest that avoided costs should be calculated based on offsetting combined-cycle natural gas facilities; a capacity value should be credited to distributed PV; and societal impacts (e.g., job creation) should be included in benefit cost calculations. They also provide a list of their key requirements for what should be included in a benefit cost evaluation.

3.1.2 Transmission and Distribution Deferrals

Distributed PV can potentially affect T&D infrastructure. Benefits can accrue if PV is able to serve local loads and relieve capacity constraints or if it can defer T&D system upgrades. Costs could be incurred if the installation of PV results in additional distribution system upgrades (discussed further below). Monetary savings depend upon the location of the PV on the grid and the coincidence of PV to peak demand. Installing distributed PV in an area where there is transmission congestion, or in regions with summer peaking, provides a greater benefit to the system than locating it in an area without congestion or regions with winter peaking (NREL 2008). While distribution systems may benefit by load relief from the presence of PV, the actual deferral of system upgrades may be limited by the need to serve peak load on a feeder and

[1] Distributed PV is providing energy value to the grid. The displaced generation source may view the addition of distributed PV as a negative value.

because these peaks may be calculated without the load-masking of PV on a feeder. NREL (2008) notes that this benefit is driven by many factors, including location (urban versus rural), temperature (spiking versus moderate), future load growth (high versus low), and the location and growth of the distributed PV. Studies of the value of deferring T&D upgrades show benefits typically less than $0.02/kWh. Jennings (2011, p. 21) found that utilities in Colorado were not able to defer or decrease capital expenditures on T&D due to the "relatively low total PV generation and the need to maintain distribution reliability." Kahn (2008) found that transmission deferrals ranged from 10% to 30% of a 10-kW PV project cost, depending on the time horizon (7, 15, or 25 years) and the discount rate used (3%, 5%, or 7%).

3.1.3 Line Loss Savings

Distributed PV reduces line losses by producing energy close to where it is consumed and at a coincident time of generation and consumption. This benefit is independent of its specific placement on the system.

The Federal Energy Regulatory Commission (FERC) estimates overall losses between the production at power plants and final consumption at between 5% and 8% across the United States from 1993 to 2004 (FERC 2007). Line loss savings from PV have been estimated in addition to the energy savings at around $0.005/kWh to $0.01/kWh, with a few studies estimating substantially higher values. For example, distributed PV located near the ends of main feeders was shown to produce greater savings in a study of Silicon Valley Power's system (the municipal utility of Santa Clara, California). The study found that optimal siting of distributed PV could reduce losses by three times the system's average loss rate (FERC 2007). Siting generation close to the consumption will have a larger impact on system losses, thus reinforcing the importance of the location of distributed PV on its valuation.

3.1.4 Fuel Price Hedge

Distributed PV can provide a hedge against increases in natural gas and coal prices. There are challenges to calculating this benefit, and while many studies acknowledge that it is a benefit, a number of studies do not quantify it (RMI 2013). Natural gas price forecasts are a key assumption and have been historically variable and considerably lower in recent years.

One method of quantification used by Clean Power Research for Austin Energy was to determine how much it would cost the utility to purchase natural gas futures contracts. Another approach used was to assume that the utility would have excess natural gas and could sell futures contracts to others. Jenkin et al. (2013) examine the fuel price hedge of solar and wind using a Monte Carlo simulation approach, comparing the benefit from solar and wind to the use of other partial price hedging mechanisms.

3.1.5 Environmental Benefit

Environmental benefits of PV include avoided air pollutants such as nitrogen oxides and sulfur dioxide and overall reduced carbon emissions. These have been quantified in a variety of ways, including putting a price on carbon, surveying renewable energy certificate (REC) prices, and estimating consumer willingness to pay for environmentally preferred electricity. Researchers have used various methodologies and proxies to quantify environmental benefits, with resulting benefits of one set of studies ranging from 0.02 ¢/kWh to 4.18 ¢/kWh (NREL 2008; Jennings 2011; AE and CPR 2006).

3.1.6 Grid Security and Reliability

Distributed PV can reduce the risk of power shortages and perhaps power brownouts by serving peak demand in instances where PV generation reliably coincides with peak demand (RMI 2013). In addition, although the vast majority of grid-connected PV systems today automatically go offline in the event of a voltage or frequency problem and have no stand-alone capability, hybrid PV systems that incorporate storage are available and can provide power during power outages (either due to natural disasters or other failures). This ability addresses an increasing public concern[2] after events such as Hurricane Sandy highlighted the need for continuous power for hospitals, emergency response centers, and lighting along evacuation routes.[3] However, the effect of PV on grid reliability is controversial, particularly if it is assessed separately from capacity value. Most studies have not attempted to provide quantitative estimates of this value due to the challenges of calculating it (RMI 2013).

3.2 Costs of Distributed PV

The costs associated with PV adoption fall not only on the PV system owner but also impact the utility, the ratepayers, and society in general. Direct system costs (which include fixed and variable costs of installing and maintaining a PV system) are borne largely by the PV system owner. Under current rate-making structures, indirect system costs may fall upon the utility and its ratepayers, including the costs of interconnecting and maintaining PV on the grid. Although these costs are low at current low penetration levels, they will increase as penetration grows beyond a certain threshold, which varies according to each utility system's characteristics. With increasing levels of distributed PV, regulators may choose to require PV system owners to incur additional costs.

3.2.1 Direct Costs (Fixed and Variable Costs)

The direct costs of PV systems include fixed and variable costs of installation and maintenance. The fixed module and hardware balance-of-system costs (e.g., inverters and mounting brackets) are readily quantifiable. Variable costs, which include the non-hardware balance of system costs (or soft costs), such as installation, interconnection (see below), permitting, financing, and operations and maintenance costs, are major contributors to the total installed costs of distributed solar. In the United States, these direct costs of a PV system are borne by the PV system owner (while in Germany, many of these costs are "socialized" by the utility and collected from all customers).

PV system owners that undertake the direct costs of installing PV are frequently supported by federal and state investment tax credits (ITC), accelerated depreciation provisions, RPS and DG

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[2] See, for example, Crane, D.; Kennedy, R.F. Jr. (2012)."Solar Panels for Every Home." The New York Times, nytimes.com, http://www.nytimes.com/2012/12/13/opinion/solar-panels-for-every-home.html.

[3] After Hurricane Sandy, the President's Council of Economic Advisors and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability also investigated grid resiliency. See Executive Office of the President. (2013). "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages." http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf.

set asides, and rebates and performance-based incentives. Most of these incentives are designed to be available in coming years, although some are scheduled to decline. For example, a number of utilities have established mechanisms to reduce the level of incentives provided over time (Bird et al. 2012) and the 30% federal corporate ITC is currently scheduled to decline from 30% to 10% after 2016, while the federal residential tax credit drops from 30% to zero after 2016.

The direct costs of installing PV generally comprise the largest portion of the cost of distributed PV. These include the cost of the modules, the balance-of-system costs, and operations and maintenance costs.[4] These costs are fairly well understood and are expected to decline over time as competition among installers, scale economies, and technologies advance (Feldman et al. 2013; Goodrich et al. 2012). Balance-of-system costs have also declined, though less dramatically. Both are expected to continue to decline, although little reduction may be expected in inverter costs (Ardani et al. 2012; Bony et al. 2009). Inverters, in fact, may increase slightly in cost due to new inverter technology aimed at alleviating grid issues associated with high penetration of DG. Smart inverter advanced functionality is already required in Germany and is being considered as a requirement as California's Rule 21 (DG interconnection rule) is revisited (CPUC 2012).

Total direct costs vary according to system size. Residential systems are the most expensive on a per-watt basis; wholesale DG systems are the least expensive. Barbose et al. (2013) surveyed installed PV prices, finding that systems less than or equal to 10 kW declined to a median cost of \$5.3/W; systems between 10 kW and 100 kW dropped to a median cost of about \$4.9/W; and systems larger than 100 kW dropped to a median cost of \$4.6/W. These costs represented declines of 14% (systems ≤10 kW), 13% (systems 10–100 kW), and 6% (systems >100 kW) from 2011 costs.

Feldman et al. (2013) reported that data available to date appear to show that PV costs dropped sharply in 2012. Figure 4, from that report, shows the trend in PV prices and includes estimates of 2013 and 2014 installed costs for residential, commercial, and utility-scale systems.

3.2.2 Administration Costs

The administration costs of distributed PV, which often include billing, customer communications, and incentive program costs, may be borne by utility ratepayers. The literature on administrative costs typically report them as relatively low compared to other costs. For example, according to Crossborder (2013b), Southern California Edison (SCE) has representative costs of \$2 to \$3 per month per net metering customer. Although Pacific Gas and Electric (PG&E) reported manual incremental billing costs at close to \$30 per month per net metering customer, they grant that PG&E is an outlier relative to other utilities. Hoke and Komor (2012) state that administrative costs are 'low' and make no attempt to quantify them. Several valuation studies do not even mention administrative costs (Navigant 2010; APS 2009). Bradford and Hoskins (2013) hold that administrative costs should be accounted for, arguing that the costs increase with increased PV penetration levels, but the costs they point to are associated with interconnection and planning rather than billing or customer relations.

[4] The balance-of-system costs include items such as wiring, conduit, inverter, structural costs like site preparation and racking installation and business process costs.

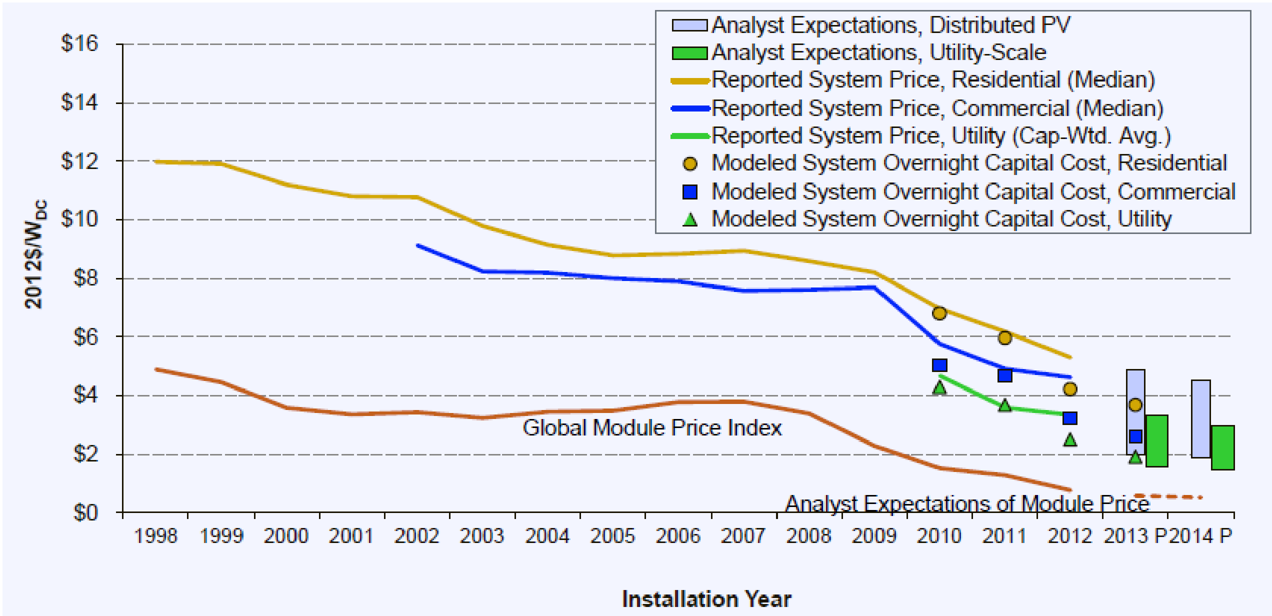

Figure 4. Reported, bottom-up, and analyst-projected average U.S. PV system price over time

Source: Feldman et al. (2013)

Note: The reported system price for the residential market is representative of the median price reported for systems less than or equal to 10 kW in size; the median size of these systems is 5.0 kW. The modeled residential system price represents a 4.9-kW system. The reported system price for the commercial market is representative of the median price reported for systems greater than 100 kW in size; the median size of these systems is 281 kW. The modeled commercial system price represents a 217-W rooftop system. The reported system price for the utility-scale market represents the capacity-weighted average of reported systems greater than 2 MW in size; the capacity-weighted average size of these systems is 18.3 MW. The modeled system price of utility-scale systems represents a 187.5-MW fixed-tilt ground-mounted system. Bottom-up system prices are representative of bids by an installer in the fourth quarter of the previous year. The Global Module Price Index is Navigant Consulting's module price index for large-quantity buyers.

3.2.3 Interconnection Costs

Interconnection costs are the costs associated with the infrastructure needed for safe and reliable interconnection of the power plant to the grid. Many state interconnection rules follow the IEEE 1547 standard, and there are limited costs associated with interconnection of smaller PV systems. However, as levels of DG on the system increase beyond a threshold, reliability and power quality issues are expected to arise that may require additional impact studies or the investment in technology improvements during the interconnection process (Navigant 2010 and 2011; SCE 2012; E3 2012). These may include investments to support voltage regulation, upgrading transformers, increasing available fault duty, and providing anti-islanding protection through advanced communications technology.

Increased PV penetration can cause voltage changes that exceed the tolerance of installed equipment. As a result, higher PV penetration may require advanced inverters so that voltage can be regulated at the system owner's site, or it may require upgrades in substation voltage regulation, improvements in distribution lines, or upgrades in transformers.

One threshold of the percentage of PV penetration incorporated into many DG interconnection rules is 15%. The assumption is that no special system studies are required until the amount of DG capacity exceeds 15% of the peak load experienced on a distribution line section. This does not mean there will need to be upgrades but determines whether a PV system is eligible for fast track review. In reality, the need for system upgrades will vary according to system characteristics and location. In some cases, significantly more distributed resource can be deployed with no negative effect or need for upgrades, so the 15% threshold should not be considered a technical limit (Coddington, 2011; E3 2012; Navigant 2010; SCE 2013).

Case Study: Southern California Edison

Southern California Edison (SCE) is expecting rapid PV growth on its system over the next five to seven years as it meets its share of Governor Brown's 12,000-MW distributed PV goal. PV location is currently driven by customer demand and its location is not targeted to those areas of the distribution system that can accommodate new capacity at least cost or with greatest benefit. As a result, Edison expects continued growth on rural feeders where interconnection upgrade costs will be high and they expect continued penetration on some circuits where PV production is already in excess of 30% minimum circuit demand. The cost estimates available are not yet vetted, and it is unclear how they will account for smart inverters, the possibility of Low-Voltage Ride-Through (LVRT), and potential for limiting the need for higher cost upgrades through the use of curtailment (Hoke and Komor 2012).* The SCE study shows that PV in rural locations that are not guided toward preferable locations will have installation costs of $330/kW to $570/kW, while "guided" PV installations in the preferable rural areas will experience realized costs of about $90/kW. In urban settings, "unguided" PV installations not guided toward preferable areas incur costs of $321/kW, on average, and guiding the location does not produce the large cost reduction observed in rural locations (SCE 2012).

*Low-Voltage Ride-Through (LVRT) refers to a situation where system protection devices such as inverters automatically "ride through" low-voltage events. Conventional inverters and the IEEE 1547 standard implemented in most places do not allow LVRT and instead shuts off DG systems if unacceptable even modest (the limits are not that bad, so this is not characterizing 1547 fairly!) declines in voltage occur. Allowing LVRT (IEEE 1547a allows greater levels of LVRT, but not mentioned) thus reducing the number of events where DG is shut off for system protection purposes.

DG interconnection implemented in accordance with IEEE 1547 and UL1741 includes anti-islanding provisions, which protect DG systems from continuing to operate during a power outage or other grid failure. If DG supply exceeds electricity demand on a circuit, the circuit could "island" from the system as a whole and self-provide. Utilities generally have poor visibility of electric flows within circuits, so islanded operation can cause power quality impacts and concern for safety. Anti-islanding equipment turns off local generation if an island situation is detected. The IEEE 1547 interconnection standard requires all distributed PV to be installed to prevent islanding of a portion of the distribution system. As penetration of distributed PV increases, dropping it in this fashion will pose reliability challenges that could require investment to improve circuit visibility and control (so that islanding is not necessary) or investment in ancillary services to compensate for these abrupt losses of DG. Increasing PV penetration could necessitate investment in more advanced sensing and control equipment to maintain visibility for system operators and prevent islanding without unnecessarily shedding local DG.

The actual interconnection cost for necessary system upgrades is generally low for most PV penetration levels to date, but increasing deployment may require more investment. The need for utility system and PV system upgrades will vary according to system characteristics and location. In some cases, significantly more DG can be deployed with no negative effect or need for upgrades (Navigant 2010; SCE 2013). Allocation of increased interconnection costs may need to be worked out over time through interconnection rules and rate structures.

3.2.4 Integration Costs

Integration costs are operating costs associated with managing DG on the utility system. The unique characteristics and performance of the PV can impose operational costs on the rest of the system. While interconnection costs are typically one-time investments, such as system upgrades, integration costs are continually occurring costs related to maintaining system integrity.

Higher deployment of distributed PV has implications for system operations because of the variability in production due to cloud cover as well as the fairly rapid changes in output that can occur at sunrise and sunset. The latter changes are predictable but will affect unit commitment decisions at substantial PV penetrations. Variability in output from cloud cover is smoothed out with the aggregation of many distributed PV systems that are dispersed geographically because they are not all affected by clouds at the same time. However, overall, PV variability may lead to the need for additional balancing reserves and can also lead to increased stress on conventional generating units due to more frequent cycling. The Western Wind and Solar Integration Study Phase 2 found that high wind and solar penetrations (33% of energy) increase operations and maintenance costs of fossil fueled generators by $0.48/MWh to $1.28/MWh. From a system perspective, these costs are relatively small compared to the fuel cost savings of wind and solar, however, with cycling costs of $35 million to $157 million compared to $7 billion in avoided fuel cost from 33% wind and solar (Lew et al. 2013).

Navigant's 2011 study of solar impacts on the NV Energy electric system shows that integration costs are low as long as the penetration of solar resources (utility-scale and DG) is relatively low. Cost estimates range from $3/MWh to $7/MWh for penetration levels of 10%–20% of system load. These cost estimates are consistent with the range of costs for integrating wind ($0 to $7.50/MWh) shown by Wiser and Bolinger (2012). As more PV is deployed, it could become important for regulators to evaluate the allocation of integration costs among customers, while also considering that all generation imposes costs and benefits on a system. For example, large baseload thermal generation requires flexible generation support due to its inability to ramp quickly, yet also provides the benefit of providing low-cost continuous power. Historically, system costs have not been borne by specific coal or nuclear generation units but have been paid by all ratepayers (Milligan et al. 2011). Assigning integration costs to PV could be warranted if PV integration costs exceed those of traditional resources or if all generation sources share in integration costs to ensure system reliability.

3.3 Considerations for Regulators

Regulators now face a new challenge as they seek to determine the cost effectiveness of distributed PV programs. The challenge, however, is not unfamiliar. Regulators have addressed the regulatory challenges associated with adopting beneficial levels of energy efficiency on utility systems. They have worked to identify the sources of benefit and cost, made intentional choices on how best to evaluate energy efficiency programs, and implemented screening criteria that identify cost-effective programs. Many states have also implemented decoupling policies to overcome barriers to implementing effective energy efficiency programs, in particular the challenge of the utilities' lost revenue due to decreased electricity sales.

Regulatory issues associated with distributed PV are more complex than those of energy efficiency, but the steps to tackling the challenge are similar. It is possible that addressing the regulatory and rate-making issues related to DG, demand side management, and efficiency simultaneously may lead to more effective end solutions and support efficient deployment of these interrelated technologies.

Economically based regulation requires the benefits and costs of distributed PV to be identified and quantified to the extent possible. Regulators may struggle to determine how much distributed PV may lead to the greatest benefit to cost ratio, from the societal perspective. Screening criteria for determining the benefit/cost performance could help with this challenge, as could rate structures that send price signals that are consistent with the screening criteria.

Regulators may consider benefits such as energy and capacity, T&D system deferrals, line loss savings, fuel cost hedging benefits, and environmental and health benefits. The costs include direct equipment costs, operation and maintenance costs, program administration and interconnection costs, and integration costs. Transfer payments between and among consumers and state and federal tax payers may also be relevant for the screening criteria selected. Additional criteria that are used for energy efficiency, including the total resource cost test, the societal test, and the utility cost test are also candidates, in adapted form, to be screening criteria for distributed PV (Woolf et al. 2012).

Screening criteria that are in line with regulators' evaluations of benefits and costs can then be developed. These criteria could, in turn, inform regulatory and public policy. This will affect the build-out of distributed PV, the development of utility business models, and future utility rate designs.

4 Business Models for Distributed Generation

As the cost of solar technology declines and improvements are made in smart-appliances and storage technologies, the relationship between the customer and the utility will continue to change. New business models for distributed solar have already appeared and will continue to develop as the market continues to mature. Utilities may choose a variety of responses, and it will be up to policymakers to ensure that the appropriate regulatory framework is in place to address the market changes and utility reactions. Regulators may need to consider customer equity issues, the need for sufficient utility revenues to maintain a reliable distribution service, and how to support continued increases in distributed solar and capture its true value to the system.

By encouraging alternative business models and adjusting rate recovery mechanisms, regulators can encourage or discourage utilities to participate in distributed solar. This will ultimately affect the balance between the provision of distributed solar services by third parties versus by utilities. As a result, regulators may want to consider the potential effects of proposed regulatory actions on the balance within the market.

This section discusses several business models that can enable distributed PV development. The first set of business models discussed represents today's common model of customer or third-party ownership of PV systems. A utility's involvement in these business models is limited to its role as the owner and operator of the broader electric system to which the solar system connects and perhaps as administrator of a public purpose program that incentivizes customers to invest in solar. However, there is increasing interest in utility business models for DG, in which the utility takes a more central role.[5] These models are the second set of business models discussed in this section. Some of these models are being piloted while others are still theoretical.

Given that distributed PV investments are occurring within the context of a broader electricity system, some argue that it is unlikely that the full benefit of DG technologies can be realized without a greater degree of utility involvement and perhaps some degree of utility ownership (Frantzis et al. 2008). Among the options, the utility may choose to be proactive in this arena by recognizing the trends toward increasing DG and engaging in business measures that will strengthen its financial integrity within this changing business environment. However, there are challenges and barriers to overcome.

4.1 Customer and Third-Party-Owned Distributed Solar Models

4.1.1 Customer-Owned Model

This business model is the original solar procurement model in which homeowners own and install a solar system on their properties and arrange for the financing and system maintenance themselves. A variety of mechanisms have been established to assist customers in purchasing PV systems. These include state loans, grants and tax incentives, bulk-purchasing programs, and Property Assessed Clean Energy (PACE) financing.

[5] See, for example, Richter (2013), Lehr and Binz (2013), IEA-RETD (2013), Rocky Mountain Institute (2013), and Sioshansi (2012).

State loan or grant funds can reduce the overall cost of a system for a homeowner. Customers receive further assistance through investment tax credits that allow offsets or refunds on income taxes. These can increase the payback of the initial investment by the customer and help make the system more affordable, especially in cases when state and federal programs operate in tandem.

Bulk-purchasing programs aggregate consumer demand to offer reduced prices on the purchase and installation of systems. Across the country, city governments, collaborative partnerships, and private companies have offered a variety of bulk-purchasing programs that are tailored for both homeowners and commercial customers.

Another mechanism developed to help finance customer-owned systems is PACE financing. Under PACE, local governments with enabling legislation can raise capital through bond financing and lend that money to eligible customers to install distributed PV at lower interest rates. The customer repays the loan through an assessment added to his or her property tax bill. If the customer sells the house, the obligation stays with the property—not the original contracting party—and the new homeowner has notice of the obligation (DSIRE 2013; NREL 2010).

The PACE mechanism ran into challenges when some mortgage lenders questioned the priority of the debt. The issue remains unresolved for residential customers, but it has been able to proceed for commercial properties.

4.1.2 Third-Party Leasing Model

The third-party leasing model is similar to the customer-owned model except that the customers do not own the solar system themselves. Instead, a third-party solar PV developer builds, owns, and maintains the PV system at the customer site and assists in the connection of the system to the grid and the associated contract with the utility. The specifics of contracts vary, but the customer either leases the equipment or has a power purchase arrangement with the third-party developer, generally over a 20-year contract period. This means the customer can avoid the upfront cost of purchasing a solar system or the need to find financing. Often, the total of the lease payments is less than the total cost of electricity that the customer would have purchased from the utility over the course of the contract. The contracts vary in their details, such as how excess generation is credited and how RECs are handled. As with other types of behind-the-meter generation, the customer may be able to obtain payments or credit from the utility for any excess generation that the system puts back onto the utility grid. This tends to encourage efficient electricity use.

In states with regulated utility environments, the leasing or power purchase models may require the passage of state legislation that specifically allows for the sale of electricity from a non-utility company to a consumer. This is generally not the case in restructured environments, where retail competition exists.

4.1.3 Community Solar Model

In the community solar procurement model, individuals own or lease an interest in a share of a solar PV system that is typically not located on their property.[6] This model enables customers who rent their homes, who do not have a suitable location for a solar system, or who do not want a solar system on their own property to participate in solar. Much like the bulk purchasing option, the aggregation of consumer demand allows for efficiencies in equipment purchasing, installation, and operations and maintenance costs. Community solar projects can be a wide variety of sizes from relatively small-scale to large-scale installations.

Participants in a community solar project typically lease the solar equipment or purchase the electricity produced by the system. There are a wide variety of program structures and contractual arrangements, which have various implications for how the participants and the project host derive benefits from the program.

Publicly owned utilities have taken the lead in establishing community solar projects, but projects can also be hosted by a third party, a not-for-profit organization, or an investor-owned utility (see the discussion of utility community solar below). Financing can be provided by the participating customers' investments, by grants or contributions, or by the utility or ratepayer subscriptions. When the community solar project is offered by a utility, whether it be municipal or an investor-owned utility, it is similar to the purchase of generation. It may not impact utility distribution sales or revenue unless virtual net metering is used. With virtual net metering, the meter on the customer's property is considered to be virtually attached to the community solar installation, allowing community solar production to be subtracted from electricity used at the customer's property.

One challenge facing community solar projects is establishing a program design that allows project investors to take advantage of the various tax incentives for solar energy. Investor-owned utilities can typically take advantage of tax incentives, but municipal utilities and non-profit organizations may be exempt or may lack the necessary tax appetite. Federal residential and commercial solar tax credits are designed for projects that are installed on the investor's site, making it difficult for community solar projects to reap their benefits. Often the answer is forming a separate business entity to own the community solar project, but this can be an expensive and complex endeavor.

4.1.4 Customer Demand Aggregation

A few restructured states, such as Massachusetts, Ohio, Illinois, and California, permit the aggregation of customer demand for clean energy, including solar. A local government or a trade association, such as those representing retail merchants, can undertake this aggregation effort. Under this model, often called community choice aggregation (CCA), the aggregator contracts with a generation supplier for the purchase of delivered electricity (generation) with a specified amount of renewable energy, which could include distributed solar energy. This is different from the aggregation of demand for PV systems (equipment) that was discussed above. As such, the impacts on the distribution utility are minimal because the customers' consumption of electricity is not diminished as it is with customer-owned or third-party-leased PV systems.

[6] Some shared solar projects are located on multi-unit apartment buildings.

4.2 Utility Investments in Distributed Solar

4.2.1 Utility Build-Own-Operate/Utility Turnkey DG Systems

Some utilities have begun building and owning small-scale distributed solar systems within their territory. If the utility owns the distributed systems, it can earn a return on the assets and gain revenues from the sale of the electricity generated. In essence, the distributed system becomes another supply resource for the utility's portfolio.

Case Study: Duke Energy

Duke Energy is one utility that is investigating the utility ownership model. In 2009, Duke Energy began installing distributed solar on office buildings, warehouses, schools, and manufacturing facilities in its North Carolina territory. The sites were selected based on landowner interest, grid access, and the solar generation potential. Duke owns the systems and the energy it generates while paying the landowners an annual rental fee. The utility values the experience gained from owning and maintaining distributed renewable energy systems, citing the benefit of increased flexibility in the future (Duke Energy 2013).

With this approach, the utility will gain revenues from the sale of the electricity generated by the system it owns. In some cases, these utility activities may be required to operate under a separate subsidiary to conform to anti-trust law. In that case, the revenues from the utility activities in distributed solar would inure to the separate business, not to the distribution utility. Whether a separate business entity is required may depend on if the utility is vertically integrated or restructured, in other words, what responsibility the utility maintains for assuring there is an adequate supply of capacity.

Case Study: Dominion Virginia Power

On April 6, 2011, the Virginia Legislature passed HB 1686 directing the Virginia State Corporation Commission ("SCC") to consider for approval petitions filed by utilities to own and operate distributed solar generation facilities and to offer special tariffs to facilitate customer-sited distributed solar generation (see Virginia Acts Of Assembly, 2011 Reconvened Session, Chapter 771, http://lis.virginia.gov/cgi-bin/legp604.exe?111+ful+CHAP0771). The program is limited to an aggregate rated capacity of up to 0.20% of each electric utility's adjusted peak load in 2010.

Dominion Virginia Power filed a petition with the SCC on February 29, 2012, to operate a five-year pilot program funded at $80 million. The program has two parts, one supporting customer-owned distributed solar system, and another for utility-owned distributed solar generation. The installations can range from 500 kW to 2 MW, with a target of 30 MW of total capacity for the pilot program (see Application of Virginia Electric and Power Company, Order entered 11/28/2012, Docket No. PUE-2011-00117, http://www.scc.virginia.gov/newsrel/e_dvpsolar_12.pdf).

Under the program, customers provide a site for the installation and operation of a utility-owned solar DG system. The principal sites are located on the rooftops of leased commercial, industrial, and/or governmental property. The installations are targeted between 0.5 MW to 2.0 MW. The power from the solar array does not pass through the customers' meters. Rather, it travels directly into Dominion's distribution grid. The customer benefit takes the form of the lease payment for the use of their property.

On May 2, 2013, Dominion Virginia Power picked Old Dominion University to be the first participant in the Solar Partnership Program. The project will include the installation and operation of more than 600 solar panels on the University's student center. The array will generate 132 kW for the electric grid.

Utility development and ownership of distributed PV draw on the utility's existing relationship and connection with the customers. The model also makes use of the utility's creditworthiness for financing the systems, as well as its bargaining power to obtain products in bulk. However, installing small-scale distributed systems is not in most utilities' lists of core competencies, so there could be a steep learning curve if the utility does not outsource the installation. A separate business unit within the utility may be established to develop the specific capabilities required for the development and maintenance of distributed generation. As utilities incorporate smart grid technologies, improve forecasting of intermittent generation, and resolve other integration issues, they may realize the benefit from strategically placing distributed generation on the grid.

4.2.2 Utility-Led Community Solar Projects

As mentioned above, most utility-led community solar projects to date have been initiated by municipal or cooperative utilities. However, investor-owned utilities can host community solar projects, as well. These projects differ from the more familiar utility green pricing programs. Under a green pricing program the utility procures or generates a certain amount of electricity from renewable sources on behalf of a participating customer. The customer may be unaware of what type of renewable energy technology is being used or where it is located. With a community solar project, the customer is purchasing a portion of the capacity of, or generation from, a specific solar system. In this way, community solar projects can be designed to provide consumers with a hedge against electricity price increases.

Utilities can choose to offer community solar projects for a variety of reasons, including customer demand to participate in solar energy development, state policy requirements for renewable energy, and benefits to the distribution system. Some states are now requiring utilities to offer a community solar option. Utilities have more experience with managing larger-scale projects as compared with small PV systems on single-family homes, so the community solar model may be more in line with their existing expertise than the utility build-own-operate/turnkey model.

Regulators have a key role in determining whether utilities will be able to recover costs of investments in utility-led community solar projects, which will help determine the economic viability of this model. Although investor-owned utilities are eligible for the federal investment tax credit for commercial solar projects, they may not be able to maximize the value of the credit due to normalization rules that require utilities to spread the tax benefits of investments over the lifetime of the project. In addition, power purchase agreements affect utility risk and capital via imputation. Private developers have more flexibility in using the credit that often gives them an economic advantage in developing solar projects. Adjusting normalization and ratemaking rules to better accommodate utility community solar projects could encourage their expansion.

4.2.3 Utility Partnership and Investments in Third-Party Leasing Companies

In this model, a utility partners with or invests in a third-party leasing company that supplies PV systems to the utility's customers. A wide variety of partnership arrangements, with varying benefits for both the utility and the third-party developer, can be imagined.

For a vertically integrated, fully regulated utility, working with a leasing company can provide a supply option as part of an integrated resource portfolio. The vertically integrated utility could obtain revenue on its investment in the solar company if it is able to show regulators that it has invested in distributed resources that are part of its resource supply and that its ownership share of the asset should be placed in rate base. The utility could own the assets (for which it could recover its investment costs and a return), and the third-party developer would be compensated for providing the development and maintenance services. Under this scenario, any profits made from the leasing agreement would flow back to the consumer in the same way as would profits from an off-system sale. Working with a third-party leasing company in this way may give the utility an opportunity to build competency and gain needed experience with distributed solar. In addition, a utility partnership with the leasing company likely provides additional assurance to homeowners considering solar leasing.

Under some decoupling mechanisms, utilities no longer have a disincentive to encourage customer efficiency or self-generation. For a vertically integrated utility, the effectiveness of decoupling in addressing the throughput disincentive will depend on whether the decoupling mechanism extends to the entire rate or just the distribution portion of the rates. Municipal utilities could potentially form a non-profit leasing company to provide the leasing option within their provision of service, given legal authority under the law and ratepayer/investor approval.

Case Study: PG&E

PG&E has engaged in two tax equity financing agreements with solar system developers Solar City and SunRun, which offer solar system leases and PPAs directly to consumers. Under the agreements, a subsidiary of the utility, Pacific Venture Capital, provides upfront financing for new solar energy systems and receives revenues from the leases of solar customers. In addition, the utility is able to take advantage of federal investment tax credits and local rebates and credits. PG&E undertook a $100 million agreement with SunRun and a $61 million agreement with Solar City, providing financing for an estimated 4,500 systems in 2010 and 2011. This is an example of a utility working with third-party developers through a separate subsidiary.

In restructured environments, this model also helps utilities attract and retain a customer base and reduce customer acquisition costs. For a utility operating in a restructured state, regulators may seek to ensure an even playing field for similar competitive enterprises by requiring, at a minimum, corporate separation and a code of conduct.

4.2.4 Value-Added Consulting Services

By building on the energy efficiency consulting services they may already provide, utilities could establish consulting expertise to provide customers with comprehensive energy services, including energy efficiency, DG, and demand-side management options. Utilities could supply customers with preliminary educational information, connect customers with appropriate third-party system installers by providing them with a list of approved vendors, help coordinate site visits and assist customers in comparing third-party bids, and provide follow-up support and surveys on behalf of installers. Installers could make a small, standardized payment to the utility for each successful customer lead provided by the utility. Other utility consulting services might be on a fee-per-service basis, paid by the customer. The utility could combine these consulting services with on-bill financing to provide a more holistic product to its customers. All of these services draw on most utilities' existing customer relations and past experiences with energy efficiency and would situate the utility as a one-stop contact for all energy-related questions and needs to simplify energy efficiency, renewable energy, and demand-side management for consumers.

A key consideration for this model is the need to ensure compliance with codes of conduct. Depending on the regulations in a particular state the utility may be required to establish a separate subsidiary to offer the consulting services under this model. The services work to increase the penetration of DG on the utility system. If the two revenue streams are separated, the income from consulting does not offset the reduction of kilowatt-hour sales induced by the increase in distributed systems. Thus, decoupling would be important. In order to avoid undue preference toward any particular vendor, and as a customer protection where the utility subsidiary is acting as a consultant on behalf of a customer, it would be important that the fee paid to the utility would be the same for all vendors. Moreover, the utility consulting operation would ideally establish a certification protocol under which any vendor can apply in order to get on the list.

4.2.5 Virtual Power Plant Operator

In the Virtual Power Plant Operator model, the utility aggregates the generation from many distributed units on its system. The focus is on the role of the utility in managing the distribution system. It uses demand-side management mechanisms from industrial/commercial customers and smart residential appliances to help balance loads with supply and relieve congestion within the distribution system. This improves reliability and delays the need for broader system upgrades. To further enhance the benefits, the utility may encourage the installation of distributed systems at strategic locations on the system, either installing the system itself or using price signals that would incentivize customer installations. The virtual power plant operator model draws on the utility's knowledge of its distribution grid and its competencies in load balancing, grid management, and customer relations. This model is very similar to the Smart Integrator or Orchestrator model, discussed by Fox-Penner (2010) and Lehr (2013). The distinction is that, here, the option remains open for the utility to participate in electricity generation or purchases, in addition to its grid management role. In other words, the Virtual Power Plant Operator model can be implemented such that the utility only provides management of the grid or provides the enhanced grid management services in addition to some generating or power purchasing role.

Case Study: Arizona Public Service

Arizona Public Service (APS) is piloting a version of the virtual power plant operator model through its Flagstaff Community Power Project. APS installed, owns, and operates distributed PV systems on homes and schools across Flagstaff. The electricity generated is not net metered but sent directly to the electrical grid. Data on the generation of each system are collected, however, and made available to participants. In return for hosting a solar system, pilot program customers are given a fixed electricity rate effective through 2030. The utility is using the pilot program to better understand the effects of high penetration of distributed solar on the system, test smart grid applications, and learn to maximize both utility and customer economic benefits.

Because the utility retains ownership of the DG systems in this model, the utility gains revenue from the sale of electricity and can claim the systems as assets during the rate-basing process. However, the value may be highly location-specific and the benefits may be challenging to calculate. More pilots, such as the APS pilot project described above, would be helpful. The utility would also need to weigh whether it is ultimately more cost-effective to install DG at customer host sites and compensate them through a reduced rate over a 20-year period or acquire its own sites and forgo working with customer sites. The benefit of working with the customer is the educational value for the customer and information a utility may obtain on the impact of the DG in a particular load pocket so as to better manage its system. Thus, this approach, depending on the economics, may work better in pilot form as an educational laboratory.

This model is similar to the utility-build-own-operate (turnkey) option; however, in the turnkey option the utility pays a leasing fee to the customer for the use of its property to install the distributed solar. In the virtual power plant option, the customer instead receives a reduced electricity rate. Under both models, notable benefits to the utility include the ability to put the solar assets in the utility rate base and to strategically locate distributed solar on the grid to obtain optimal value and efficiency for the overall electrical system.

4.3 Energy Services Utility Model

Unlike the models above, the energy services utility model does not represent a method of utility investment in distributed solar. Rather, this model represents a business focus on providing specified services and employing rate structures that capture the value of the provision of those individual services. In other words, rates are designed to ensure that customers who use a particular utility service pay for the value (the complete costs) of that service, and customers who do not use the service are not required to pay for it. This model increases equitability across utility customers (whether they invest in DG or not) and ensures that utilities and DG owners are appropriately compensated for the services each provides (Fox-Penner 2010; Lehr 2013).

In this model, utility pricing is not based on the amount of energy provided but on the value of services provided by the utility. Customers select from a menu of services that they require. These could include traditional services needed by customers without DG, such as traditional generation, T&D service in regulated states. In restructured retail market states, the generation service could be separately acquired. It would also include services important to the owners of a distributed solar system, such as the provision of backup generation and off-loading of excess generation onto the grid. This model ensures that, although the number of kilowatt-hours sold by the utility is reduced as DG proliferates, the utility is compensated for the services it provides to distributed system owners. Likewise, a menu of services offered by distributed generators to the utility would be defined, including RECs, peak shaving, and ancillary services. The potential value of this menu of options is that it attempts to create fairness among ratepayers with and without DG by appropriately distributing the remaining system costs. By the same token, it compensates the DG owner for services the utility would have had to obtain elsewhere. This compensation for services is important in that it helps the DG owner off-set investment costs and protects the incentive for selecting DG. Precedents for such payments from utilities to customers exist in the form of contracts between utilities and large customers that provide regulation and synchronized reserve services.

A key component—and benefit—of this model is its ability to more equitably distribute costs across all utility customers. Distributed generators pay the full cost of the T&D and electrical backup services they require while being compensated for the energy they contribute to the grid, the ancillary services, and the environmental benefits. Although existing distributed generators may face cost increases associated with a switch to a menu of utility services, these costs could be offset, in full or in part, by payment for services provided to the utility. Most of these costs to DG owners would be allocated to the distribution rates and help ensure that the utility can continue to operate its system reliably. On the other hand, the payments made by the utility for the DG's RECs would come from the generation portion of the business and would not draw on the distribution revenues needed to operate the business.

The energy services utility model could be of value to all utilities experiencing a boom in distributed solar. The challenge is to accurately price the wide variety of services that are provided by DG owners and by the utility and create a system of revenue exchange based on services rendered, all while protecting the interests of the utility, the distributed system owner, and the remaining ratepayers.

4.4 Key Business Model Considerations for Regulators

The various business models outlined in this section raise several considerations for regulators. These focus on maintaining customer equity and grid reliability, taking advantage of the benefits that solar can provide to the system while accounting for any costs, removing the utility disincentive to support increasing numbers of distributed systems, and ensuring that there is a variety of opportunities for customers to participate in distributed solar. Inherent in this is the need to consider the appropriate balance between services provided by third parties versus services provided by the utility. Regulators are in a position to influence this balance through the ways in which they encourage or discourage various models for utility participation in distributed solar.

Utilities have a plethora of options for investing in distributed solar. These vary based on whether the utility is operating in a regulated or restructured market that has competitive retail service. A utility operating in a restructured market cannot recover the cost of a DG investment in rate base, and its interests are more narrowly drawn toward protecting its distribution rates.

A vertically integrated utility in a non-restructured market might consider the business models that allow recovery of the investment costs for ownership of distributed generation, which could be built into capacity expansion plans. Making use of the planning process to identify least cost options that can increase system reliability on both the supply and T&D side could be useful. DG can serve as supply, and it can reinforce the grid through strategic placement—a benefit that should not be overlooked. The development of distributed solar through resource planning can yield significant reliability and cost benefits for the whole system.

In restructured markets, utilities can compete to offer distributed solar services that are designed and placed to provide benefit to the utility system as a whole. However, it is important to respect the need for corporate separation and codes of conduct. To protect both customers and competitors, regulators could consider requiring any competitive utility enterprise to be spun off into a separate subsidiary and possibly strengthen regulations on development and enforcement of codes of conduct. If subsidiaries are allowed to dominate the market, they could stifle competition and innovation. Un-checked market power could result in higher rates, inferior products, or few options for customers.

Codes of conduct frequently require separate offices and communications so that the competitive affiliate does not benefit by having access to information denied to its competitors. Where there are shared services or equipment between the subsidiary and the regulated monopoly, consideration should be given as to how the use of those services and equipment are priced. The utilities generally favor having the affiliate pay at the utility embedded cost rate, which is lower than what competitors may pay. Competitors argue that any service or equipment should be offered at a market rate to all parties, lest the utility affiliate gain an unfair advantage. Likewise, operating rules and contracts between the utility and competitors have the potential to reasonably protect the utility without being unduly burdensome to the competitors. Lastly, because the utility and the subsidiary may report to the same corporate management, a concern is that management could use the distribution utility to advocate positions that will benefit the subsidiary. These are examples of some of the major issues regarding codes of conduct that regulators may need to consider in crafting rules in order to ensure a fair and level playing field that fosters competition for the benefit of the consumers.

Each business model described above has several permutations and can co-exist or can be implemented in combination with other business models. It is unclear which will be most successful in various circumstances. The business models presented here are likely not the only options, and new opportunities may emerge from the development of new technologies (such as smart grid) and innovative regulatory and policy approaches. While the emergence of new business models is likely, the form they will take is uncertain.

5 Regulation and Rate Design Options for Distributed PV

As levels of distributed PV rise, utilities can become increasingly interested in alternative rate design options. Any new rate design is developed within the context of a variety of utility obligations. Regulators are charged with evaluating whether new rate proposals are in the public interest and guided by some basic principles of tariff design, including fair apportionment the cost of utility services among ratepayers and whether investments are cost-effective, reasonable, and prudent.

This section lays out the obligations, rate design principles, and considerations for regulators that are relevant in the context of increasing levels of distributed PV on utility systems. Several rate design options that aim to address the customer equity and utility revenue issues associated with increased levels of distributed PV are then presented.

5.1 Utility Roles and Obligations

Utilities are charged with serving customers, interconnecting and purchasing power from small generators, and providing compensation for that power. From these roles and obligations, the equity and revenue impacts of increasing levels of DG arise. As such, they are critical factors in the consideration and evaluation of new rate design options.

5.1.1 Utility Obligation to Serve Customers

Society asks electric distribution utilities to deliver services that are considered vital to our economy, including safely providing electricity with a reasonable level of reliability. Society often also calls on these utilities to accomplish broader public policy objectives relating to competitive services and markets, clean energy deployment, and promoting communities through economic development.

Due to the essential nature of these services and the inefficiencies that could be associated with multiple entities serving the same geographic area, electric distribution utilities have historically been granted monopoly privileges by state and local governments. In exchange for an exclusive service franchise and the right to earn an established rate of return on investments, distribution utilities are obligated to provide reliable service to all customers at just and reasonable rates that are set through a regulatory process. This agreed-upon set of rights, obligations, and benefits has sometimes been called the 'regulatory compact' (EEI 2012).

5.1.2 Utility Obligation to Purchase Power

Pursuant to rules authorized by the Public Utility Regulatory Policy Act of 1978 (PURPA) and promulgated by FERC, electric utilities must offer to purchase electric energy from small power production facilities of 80 MW capacity or less at rates that are:

- Just and reasonable to the utility's customers and in the public interest
- Nondiscriminatory toward qualifying small power production facilities

- Not in excess of the cost to the utility of generating or purchasing such electric energy from a source other than the qualifying facility.

Furthermore, the FERC rules require each utility to offer standard rates for purchases from all qualifying facilities with a design capacity of 100 kW or less.[7] Utilities have discretion on whether to offer standard rates or to negotiate rates for purchases from facilities larger than 100 kW.

These PURPA requirements and FERC rules are relevant to the discussion of distributed PV because almost 98% of PV installations in the United States are smaller than 100 kW.[8] Although the number of larger installations is expected to grow, many PV installations will likely continue to fall under the PURPA facility limits. Thus, utilities must offer to purchase the output from these qualifying distributed PV systems through a standard rate tariff that is just and reasonable.

Historically, the avoided costs rates for generation from qualifying facilities (QF) under PURPA have been calculated based on the generation from large, conventional fuel facilities. But PURPA specifies that states and non-regulated utilities may adopt differentiated rates in order to compensate QFs for quantifiable grid benefits based on their locational and supply characteristics. This means that PURPA provides a mechanism to support the development of DG close to loads, where the value of DG is highest, and to compensate those system owners for the benefits they provide to the grid (Keyes 2013).

5.1.3 Net Metering and Interconnection

In addition to requiring utilities to offer to purchase electric energy from qualifying small power production facilities, PURPA established federal ratemaking standards for electric utilities. These standards were later amended by the Energy Policy Act of 2005 (EPACT) and EISA. EPACT is particularly noteworthy with respect to distributed PV because it added, among other things, specific ratemaking standards for net metering and interconnection.[9]

These laws required that state regulators (with respect to electric utilities for which they have ratemaking authority) and non-regulated electric utilities consider each federal ratemaking standard, and, within one to three years (depending on the standard), determine whether or not the standard is appropriate to implement. For any standards not implemented, EPACT requires a publicly available, written explanation.

The federal net metering and interconnection standards state that each electric utility shall make available, upon request, net metering service and interconnection service to any electric consumer that the electric utility serves. PURPA defines net metering as "service to an electric

[7] The FERC rules for small power production facilities are codified at 18 CFR 292. Utilities are relieved of the obligation to purchase if the small power production facility has nondiscriminatory access to wholesale markets for the sale of electric energy and capacity. FERC's current rules establish a rebuttable presumption that small power production facilities at or below 20 MW in capacity do not have nondiscriminatory access to markets, and a rebuttable presumption that facilities greater than 20 MW do have nondiscriminatory access to the ERCOT, MISO, PJM, NYISO, and ISO-NE wholesale electricity markets.
[8] Based on August 2013 query of NREL's Open PV Project Database.
[9] Refer to 16 USC 2621(d) for the current version of federal law, as amended. The standards for net metering and interconnection are at 16 USC 2621(d)(11) and (15), respectively.

consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period" (16 USC 2621(d)(11)). Interconnection services are to be offered based upon the Institute of Electrical and Electronics Engineers' Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems.

Even though implementation of the federal ratemaking standards was not mandatory, utility regulators in nearly all states have implemented net metering tariffs for the utilities they regulate, as shown in Figure 5.[10] In addition, in more than half of the states, some or all of the non-regulated utilities offer net metering tariffs.

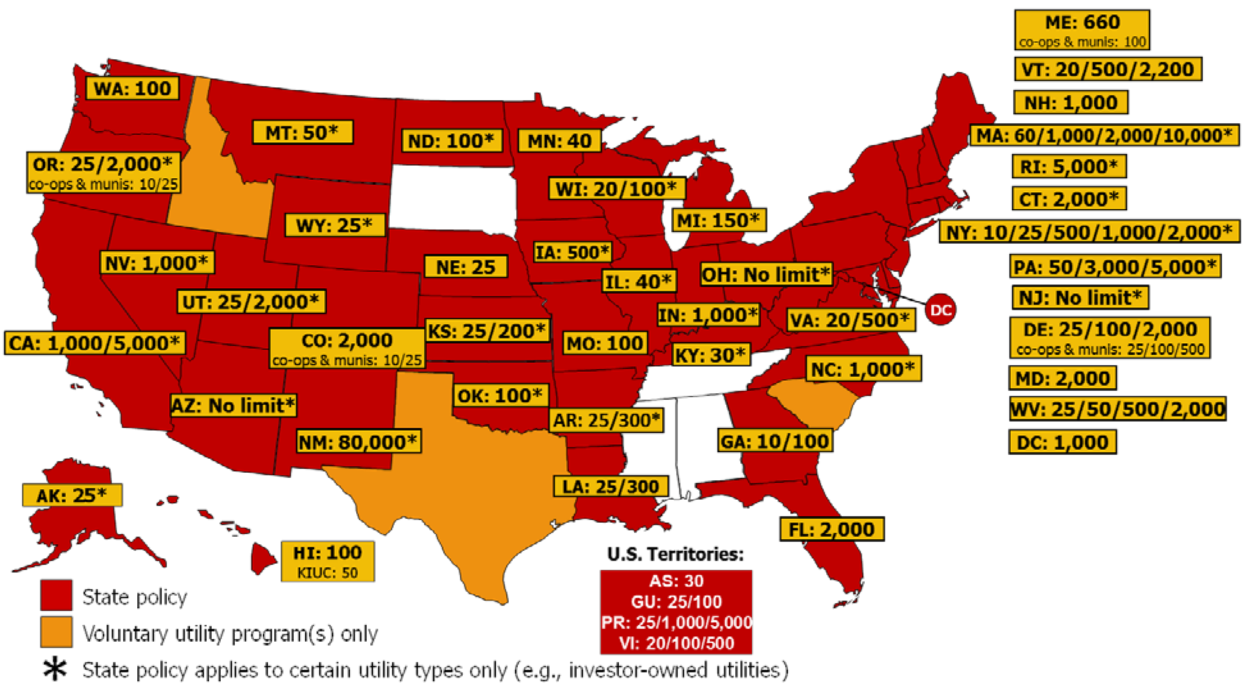

Figure 5. State net metering policies

Source: DSIRE (2013)

Note: Numbers indicate individual system capacity limit in kilowatts. Some limits vary by customer type, technology, and/or application. Other limits might also apply. This map generally does not address statutory changes until administrative rules have been adopted to implement such changes.

5.2 Guiding Principles for Tariff Design

The basic model for economic regulation of monopoly utilities is cost-of-service regulation: the prices that customers pay for utility services are (or should be) based on the utility's cost of providing those services. The purpose of cost-of-service regulation is to protect consumers from

[10] In some cases, state legislatures have imposed net metering policies rather than leaving these decisions to the sole discretion of utility regulators and non-regulated utilities.

paying excessive prices in the absence of market competition for providing those services. The regulator's job is to ensure that the utility charges prices that are just and reasonable.

More than 50 years ago, James Bonbright published a treatise on the theory of economic regulation, *Principles of Public Utility Rates* (Bonbright 1961). Bonbright's principles are the best known and most widely cited framework for evaluating electric utility rates.[11] This paper uses Bonbright's guiding principles to frame the discussion of tariff design options for distributed PV.[12]

Bonbright's principles can be summarized as follows:

- Tariffs should be practical: simple, understandable, acceptable to the public, feasible to apply, and free from controversy as to their interpretation.
- Tariffs should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively stable cash flow and revenues from year to year.
- Rates should be relatively stable such that customers experience only minimal unexpected changes that are seriously adverse.
- Tariffs should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers.
- Tariffs should promote economic efficiency in the use of energy as well as competing products and services while ensuring the level of reliability desired by customers.

All of these principles are relevant to discussion of distributed PV, but some are worthy of greater scrutiny because of issues or characteristics that are unique to distributed PV.

5.2.1 Fair Apportionment of Costs of Service

According to Bonbright, tariffs will, ideally, fairly apportion the utility's cost of service among consumers. Individual ratemaking—apportioning the exact costs of serving each individual customer to that customer and no others—is not practical or realistic, nor is it necessary to be consistent with Bonbright's fairness principle. Instead, the goal can be to avoid systematic unfairness in the way tariffs apportion utility service costs to different classes of customers.

In virtually all cases, customers that install distributed PV choose to remain part of the utility system and continue to realize benefits from being connected to the grid. So long as distributed PV customers remain connected to the grid, they will provide benefits to the utility system and receive benefits from the utility system. The distributed PV customer, the utility, and the utility's other customers will inevitably be affected by those system costs and benefits.

[11] Other works on electric utility rates are available such as Kahn, A.E. (1988); *The Economics of Regulation: Principles and Institutions;* the MIT Press.

[12] Some reviewers of this report argued that Bonbright only intended these principles to apply to tariffs governing sales by a vertically integrated monopoly utility *to* customers, not utility purchases *from* customers where some form of competition exists (e.g., competition from other load-serving entities or third-party PV providers).

Under Bonbright's principles relating to fair apportionment of service costs, distributed PV customers would ideally pay for the benefits they receive and be compensated for the benefits they contribute to the utility system. Because it is not realistic to design rates for individual distributed PV customers, one approach could be to design standard tariffs that are based on cost-of-service principles that fairly apportion the costs and benefits for a typical distributed PV system.

Also, reliance on traditional volumetric rates to recover both fixed and variable costs of service becomes problematic in the case of distributed PV. Utilities typically recover most of their total revenue requirement, including any authorized rate of return for shareholders, through volumetric rates (i.e., a price for each kilowatt-hour of electricity purchased). However, utilities incur many types of operating expenses that are not closely associated with the level of sales (e.g., office expenses, payroll, and customer billing). Utilities also make capital investments in generation and T&D assets that will last decades.

This raises a number of concerns, not just for fair apportionment of utility service costs but also for social equity issues. One aim of traditional cost of service regulation is to protect customers that do not have the option to select from competitive options for electricity provision. Because installing distributed PV can entail large upfront costs or financing, the concern is that wealthier customers may be more likely to be able to afford this switch in electricity provision. However, the availability of third-party leasing options removes the upfront cost barrier and has led to interest on the part of moderate income customers in some regions (Drury et al. 2012)

While new financing models complicate this issue, the concern is that if the reliance on cost recovery via traditional volumetric rates goes unchanged, the customers who can most afford to pay for energy could choose to install distributed PV and see their costs go down, while those who can least afford to pay for energy will see their costs go up. This could result in shifting the demographics of paying for the maintenance of the grid to lower income customers, who will begin to pay a disproportionate share of the upkeep of the grid. Thus, policymakers will need to ensure that those who do not have the option to install distributed PV systems will continue to be protected.

Some of the system costs and benefits associated with distributed PV depend on the scale of distributed PV deployment. This has ramifications for the application of Bonbright's principles to tariffs. When PV penetrations are low, utilities and regulators have focused their attention on the compensatory aspects of tariffs: What does the utility pay the generator? As PV penetrations increase, additional aspects of tariff design gain importance.

But the notion that tariffs could change—perhaps dramatically depending on the scale of distributed PV deployment—raises additional issues with respect to the desire for relatively stable rates and the need to avoid undue discrimination. Ideally, if utilities and regulators can establish tariffs for distributed PV that make sense regardless of the scale of deployment, they can avoid revising tariffs, avoid applying different tariffs circuit by circuit, and avoid applying different tariffs to customers depending on whether they installed distributed PV before or after grid stability issues arose. If it proves impossible to design tariffs that make sense at all penetration levels, regulators could anticipate the possibility of high penetration and plan for a transition in tariffs that is transparent and predictable for all stakeholders.

5.3 Rate Design Options

As penetrations of distributed PV reach more substantial levels, the impact on utility revenues and system fixed costs can become more significant, and aspects of tariff design beyond the compensation of generators can become more important. This section explores a variety of rate design options for addressing higher penetrations of DG. Some of these options could be used in conjunction with one another, while others are mutually exclusive.

5.3.1 Net Metering

Net metering has been and continues to be the most widely utilized tariff for distributed PV.[13] Most net metering policies include limits on the rated capacity of systems eligible for this tariff and on the total amount of eligible generation. Often these system caps are expressed as a fraction, such as 1%, of peak system load. The caps also limit the size of eligible projects; these limits vary significantly among the states (see Figure 5).

Under net metering, the output of customer-sited generation not used on-site is credited at the retail rate up to the customers' total electricity consumption. Monthly excess generation can be carried over to future months to offset net usage, although some utilities place limits on the carryover period. Net excess generation beyond the customer's usage can be credited at the wholesale rate, retail rate, or some higher incentive rate, depending on the policy. In some cases, there is no compensation for net generation in excess of annual customer use, and carry-forward accounts are reset annually. The idea has been adapted into group or community net metering to allow for a group of customers to own a single generation facility, divide the rights to its output, and have the utility make the appropriate bill credits.

5.3.1.1 Performance

Over the last two decades, governments have developed other ways to encourage renewable and distributed energy, but net metering remains the dominant tariff design for distributed PV. Crediting at the retail rate is a relatively simple and straightforward approach to compensating customers for generation that is not used on-site. The Solar Electric Power Association estimates that as of the end of 2012, 99% of installed PV systems in the United States were on net metering tariffs, totaling about 3.5 GW of capacity. With net metering tariffs now available in 43 states, the number of net metered customers has grown rapidly, as shown in Figure 6.

[13] For a more thorough discussion of net metering policies as they relate to ratemaking, regulatory processes and the value of solar discussion, please see the Solar Electric Power Association's report, "Ratemaking, Solar Value and Solar Net Energy Metering – A Primer," available at http://www.solarelectricpower.org/media/349530/sepa-nem-report-0713-print.pdf.

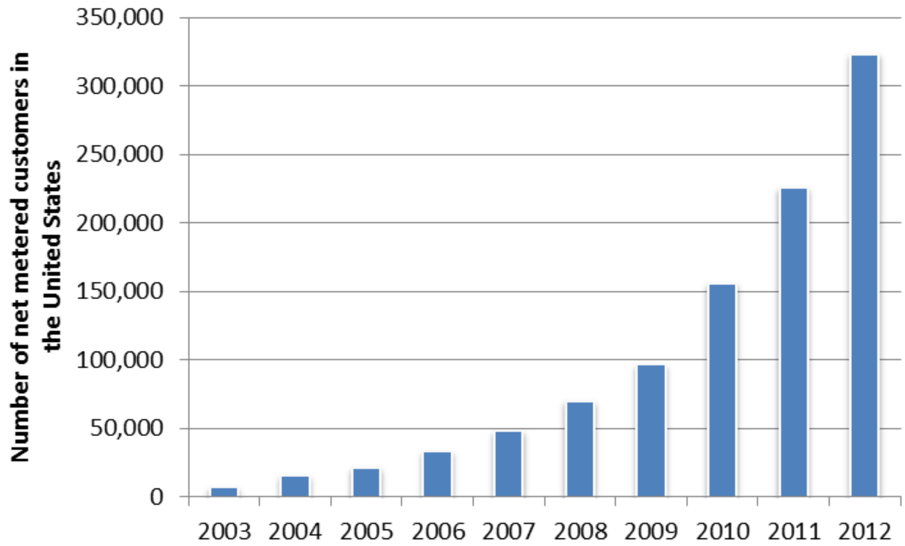

Figure 6. Number of net metered customers in the United States

Source: U.S. Energy Information Administration (2013)

With the rapid expansion and substantial cost reductions of distributed PV, utilities and some other parties have expressed growing concern about whether net metering customers are over-compensated and in some cases have sought to reduce the availability of net metering or compensation levels. On the other hand, advocates have called for reauthorization and expansion of state and utility net metering policies and increases in eligible system size and aggregate net-metered capacity. Advocates have also sought to add innovations like group or community net metering in more jurisdictions, as previously discussed.

5.3.1.2 Limits and Downsides

Net metering is simpler to administer than some other rate design options, but some argue that the compensation afforded the participating customer only approximates the value of the power produced, as discussed above. Complex issues about the cost and value of electric service are usually embedded in the underlying rate design, but often without any consideration of issues related to distributed PV. Depending on the utility system and the customer's own characteristics, the customer may be over-compensated or under-compensated for the net value (costs and benefits) that they provide to the system. This means that the net metering customer is either subsidized by other customers or subsidizes the other customers.[14] At higher total volumes of distributed PV, the accuracy of the value approximation has greater impact on, and take on greater importance to, the participating customers, the utility shareholders, and the utility's other non-participating customers.

[14] So long as rates are established for customer classes, rather than individually, some level of cross-subsidization is expected. For example, two adjacent residential customers may pay the same flat rates even though the true cost of serving them is different (e.g., because they have very different load profiles and peak demands).

From the utility's perspective, revenue erosion is another concern about net metering. As previously explained, distributed PV reduces the utility's volumetric sales and the revenues that are intended to cover variable costs, fixed costs, and shareholder returns (in the case of investor-owned utilities). This becomes increasingly important at higher levels of PV deployment.

Nearly all state net metering policies include individual system size caps, and in some cases those caps are low enough to exclude commercial and industrial PV systems that might still be considered "distributed PV." In those states that have caps on the total amount of generation eligible for coverage under net metering tariffs, other ratemaking options will be needed if the caps are exceeded in situations where further use of PV is desired.

5.3.1.3 Utility Type

Net metering works best in situations where the utility is already buying and selling energy, in vertically integrated utilities, and in retail competition in which the utility is obligated to be a provider of last resort. In the case where the utility is strictly a delivery company and does not serve load, as with Texas investor-owned utilities (IOUs), the net metering rules would have to be developed to specify how payment will flow to the customer that is generating the solar electricity.

5.3.2 Fixed Charges

There is increasing discussion of ensuring sufficient utility revenues by collecting more revenue through the monthly customer charge and less through volumetric energy and demand charges, without changing the revenue requirement (see SMUD and APS examples in the text box below). In this case, the volumetric charge covers short-run marginal costs only, while the fixed charge covers fixed costs. This rate design can be applied across all customers and is relatively easy to administer. A variation on this approach might be to increase fixed monthly customer charges only for the owners of distributed PV systems, similar to other rate design options discussed below. Proponents argue that increasing fixed charges to better reflect fixed costs will help serve the goal of providing accurate price signals for efficient economic development. The size of these fixed charges and whether they are paid by all ratepayers or only DG owners are important design and equity issues.

Case Study: Sacramento Utility District and Arizona Public Service

The Sacramento Municipal Utility District (SMUD) recently raised its fixed rate for infrastructure services for all customers, both solar and non-solar. SMUD conducted significant market research to understand customer acceptance of raising the fixed charge to help cover the cost of its grid service. The results indicated high levels of acceptance for an increased infrastructure fixed charge across all customers (Frantz 2013). As a result, in 2012 SMUD raised its residential infrastructure service charge from $7.20 to $10 per month. Small commercial fixed charges were also increased. The increases were offset by a small decrease in volumetric energy charges (SMUD 2013).

Arizona Public Service Company (APS) has recently made several proposals to the Arizona Corporation Commission (ACC) to recover infrastructure costs lost as a result of increased levels of distributed solar on its system. One of the APS proposals was to implement a monthly demand charge of between $45 and $80 that would apply only to future net metering solar customers (APS 2013). The proposal met with significant resistance from customers (SNL 2013a). ACC staff did not recommend the proposal, citing that it limited solar customers' choice of rate to time-of-use metering and did not completely address any rate shifting that might be occurring. They recommended that the issue be considered within the context of a general rate case that considers all of the costs and benefits of distributed solar (SNL 2013b).

5.3.2.1 Limits and Downsides

If all or most fixed charges were to be shifted from volumetric rates to fixed monthly charges, the monthly fixed charges could increase dramatically. Where such changes have been proposed, the evidence suggests that many stakeholders are resistant to increasing the part of their bill that they cannot control or avoid (SNL 2013a). Specifically, a shift to higher fixed charges and lower volumetric charges could substantially diminish the customer's ability to reduce costs by increasing their efficiency or by deploying PV. Across the utility system, customers may be more reluctant to participate in energy efficiency or renewable energy programs that provide net societal benefits because there would be less direct benefit to the participant through bill savings.

If all customers (including those with distributed PV systems) pay for the utility's fixed costs of service entirely or primarily through monthly customer charges, then issues of cross-subsidization will be different than under net metering and other rate design options but will not be eliminated. As with the volumetric rates that form the basis of current net metering tariffs, there would still be no explicit consideration of how distributed PV customers impose different costs or offer unique benefits to the utility system. Raising the fixed charges could potentially exacerbate or diminish the cross-subsidies inherent in net metering or change who is subsidizing whom.

5.3.2.2 Utility Type

This rate design could apply equally to all utilities and serve the same purposes. IOUs may see even more benefit than other utilities if their authorized returns are collected through fixed monthly customer charges. While U.S. utilities of all types (IOU, cooperative, or public) typically recover almost all of their fixed costs through volumetric energy charges and demand charges, IOUs also recover their *return on investment* via energy and demand charges. If rates are redesigned such that more of a utility's fixed costs are recovered through a non-bypassable monthly fixed charge, the utility is more likely to be able to recover sufficient revenues to cover its fixed costs. This would reduce financial risk for any type of utility, but there is an even greater benefit for an IOU because the risk of under-earning the authorized return is also reduced if some of that return is embedded in monthly charges.

5.3.2.3 Demand Charges

Demand charges are a common element in industrial and commercial rate designs. These rate designs include fixed charges and a volumetric rate that applies to each kilowatt-hour of consumption, but they also include a variable charge based on the individual customer's peak demand. This is one way for the utility to more accurately allocate the non-energy costs of serving individual customers because the utility must design its system and plan for the ability to meet customers' peak needs. For example, if the utility acquires 1 MW of capacity to meet each 1 MW of customer demand, then a customer whose peak demand is 5 MW is generally responsible for greater costs than a customer whose peak demand is 0.5 MW. With demand charges, this distinction is addressed in a fairly straight-forward way.

Demand charges have been proposed as a possible solution to the utility revenue and cross-subsidy issues arising with distributed PV. Participating customers could be billed based on their peak demand, in a way that reflects the costs the utility must incur to meet its obligation to serve those customers even if the PV system happens to generate no electricity at the very time that the customer's native demand is highest.

Demand charges create an inherent incentive for customers to reduce their peak demand through cost-effective energy efficiency and by flattening their load shape. Because utilities acquire resources sufficient to meet peak demand, either strategy, if deployed, has the advantage of reducing the utility's overall costs of service.

5.3.2.4 Limits and Downsides

The application of demand charges to distributed PV systems would not necessarily address all of the utility's lost revenue concerns if there are some fixed costs that do not fluctuate with peak demand and remain embedded in volumetric charges. Cross subsidies may also persist, depending on which system costs are recovered through fixed and volumetric charges and based on how demand charges are assessed. For example, if a customer's peak demand occurs on sunny summer days in the late afternoon, their system were available on more than 90% of those sunny summer days, and the system were to meet all or most of the customer's peak demand on those days, then charging a rate all year long based on annual peak demand might result in the PV customer subsidizing other customers.

5.3.2.5 Utility Type

The use of demand charges is relevant to all types of utilities. Once again, IOUs may see the most benefit because the risk of under-earning is diminished when IOUs recover their authorized return through demand charges. Energy purchases vary from hour to hour, while demand charges are typically based on maximum customer demand over a month or longer. This means that energy charge revenues are more volatile and harder to predict (i.e., more risky for the utility) than demand charge revenues. In addition, with distributed PV a customer's net energy charges may fall to zero or a negative number, but the customer will likely have some positive number for maximum demand. For all of these reasons, the risk that a utility of any type will recover insufficient revenues to cover its fixed costs is reduced when relatively more of the fixed costs are recovered via a demand charge rather than an energy charge. An IOU can benefit even more because it will also recover more of its authorized return on investment via the less volatile demand charges.

5.3.3 Stand-By Rates

Stand-by rates apply to customers who sometimes rely on on-site generation for power, but who also rely on the grid for power use in excess of on-site generation (supplemental power) when on-site power is out of service for planned maintenance and when on-site power is out of service owing to a forced outage (emergency power).

Stand-by rates have been broadly applied and are important today for many industrial and commercial class customers with combined heat and power (CHP) systems. There is far less experience applying stand-by rates specifically to PV systems, even to larger systems owned by commercial or industrial customers. But in the future, as PV is used in concert with storage or in new ways for on-site reliability, stand-by rates may become more important to the deployment of PV.

Stand-by rates include elements of several other rate designs, tailored and applied to the special case of a customer with on-site generation intended to meet most or all of the customer's needs under normal conditions. The different kinds of costs incurred by the utility are disaggregated and can be charged more accurately to each customer. For example, a stand-by rate will typically apply lower charges for maintenance power than for emergency power if the customer schedules the maintenance during off peak hours. And the rates for emergency power, ideally, can reflect the unlikelihood that all customers on stand-by rates would need emergency power at the same time.

Well-designed stand-by rates increase the chance that utilities will recover revenues to pay for fixed costs. In addition, applying stand-by rates to distributed PV systems could potentially reduce cross-subsidy concerns because owners of PV systems could be charged specific and appropriate rates for the types of services they need from the utility (supplemental daytime power, nighttime power, and emergency power).

5.3.3.1 Performance

There are a number of states with stand-by rate tariffs. A forthcoming report from RAP and Oak Ridge National Laboratory (ORNL) suggests that CHP customers under existing stand-by rates can be overcharged for these services to the extent that they are subsidizing other customers (Selecky et al. forthcoming). The details of the rates matter tremendously.

5.3.3.2 Limits and Downsides

Distributed PV is different than CHP in important ways. PV systems are expected to be unavailable many hours in each day, and their output is weather-dependent and not perfectly predictable. In addition, PV systems typically require little maintenance and suffer few forced outages. There are no technical reasons why the basic concepts of stand-by rates could not be tailored to distributed PV tariffs, but applying the same tariff to CHP systems and PV systems might not make sense because of the differences in operation.

A number of states have supplemental power charges as well as maintenance and forced outage charges. For supplemental power rates, some tariffs may call for minimum and maximum capacity usage. Backup rates for outages can be recovered through monthly demand charges that compensate the utility for having power available when the customer needs it. An alternative that has also been used is to allow the customer to avoid these charges and instead pay the utility based on the price of emergency power purchased on the market.

5.3.3.3 Utility Type

From the customer perspective, the stand-by rate should not change with the utility type. Vertically integrated utilities, however, internalize all the various costs and benefits that yield the stand-by rate. Distribution utilities must pass through grid costs and benefits and combine them with their own costs and benefits, introducing some variability into the calculations.

5.3.4 Time-Based Pricing

Time-based pricing introduces to the customer the idea that the cost to produce power varies based on time of day (e.g., more expensive during business hours) and day of year (e.g., more expensive during summer months due to air conditioning loads). As a corollary, this means that generation produced by distributed PV systems also has varying value depending on when it is produced. Sophisticated versions of time-based pricing, called dynamic pricing, deliver increasingly detailed system information to customers and enable customers to adjust their power use in real time through investments in controllable and efficient end uses and on-site power supply. Over time, time-based pricing could perhaps better utilize system resources by valuing resources (including distributed PV) that deliver at times of peak and scarcity and by prompting customer behaviors that cumulatively tends to reduce the need for system resources.

Time-based pricing has been used for decades. **Seasonal differentials** recognize that power in peak times of the year (summer, winter, or both) costs more to produce. No special technology is needed except for a billing system that allows the price to change two to four times a year. **Time-of-use (TOU) rates** have also been around for decades. TOU rates charge different prices during the day, typically falling within two or three pre-determined prices and time periods; they require a data logger to be read monthly in order to match hourly usage with an hourly price. These daily price changes reflect typical daily patterns of production costs and signal to consumers when prices are high or low and do not presume any further precision. Seasonal and TOU rates can work together. Neither of these are dynamic prices in that they do not respond to or signal market conditions to customers, but they have influenced customer behavior and investments.

States are introducing dynamic pricing in order to mobilize customers to act to avoid peaks. **Critical peak pricing** tariffs take TOU rates and add a rate that appears with a few hours' notice in roughly 1% of the most costly hours. This rate may be between 3 and 10 times the average rate to get the attention of the customer and motivate whatever curtailment action is possible.

Peak time rebates offer an alternative that allows customers to voluntarily participate by reducing peak load. There is a reward payment for participation but no penalty for failure to do so. Each of these requires a modest amount of technology—communication that the program will be activated and some hourly data logging to measure a response that the utility can read later. Each of these can be usefully coupled with demand response programs that compensate customers for curtailing power use in system emergencies and high-cost events.

Real-time pricing seeks to convey more accurate signals of production costs to customers all the time. It is debated whether smaller customers want this level of precision or can respond to it, though automated responses that reduce load rather than eliminate it entirely are increasingly feasible for more end uses (e.g., lighting and thermostats). This level of response requires technology with smart grid deployment, at least upstream in the grid, and can utilize advanced meters. Customers can become responsive to system conditions during all hours, which can be beneficial in a grid increasingly served by variable resources (e.g., wind and solar). Customers can become a reliable part of the way operators balance the grid if they will respond as reliably in a low load period in May as in a high load period in July. The time-based value of storage may be best realized in the presence of real-time pricing.

5.3.4.1 Performance

There have been many deployments and pilots of time-based pricing, so there is a lot of experience to evaluate. Yet most public utility commissions that consider it for the first time, or for those that have not considered it in a long time, assume the role of an early adopter. This is because while there are winners in time-based pricing, there are also losers—customers who cannot avoid consuming at high-cost hours and would end up paying more. At least one state, New York, outlaws time-based pricing because of the political sensitivity surrounding bill increases for some low-income customers.

It is not uncommon for utilities to include time-based pricing in the tariffs they offer to qualifying facilities in compliance with PURPA. These tariffs often pay different amounts for generation on-peak and off-peak. While typically these kinds of tariffs are not specifically targeted to PV, time-of-delivery price adjustments are a key element of PV feed-in tariffs offered by utilities in California and a few other jurisdictions.

With respect to distributed PV, time-based pricing can be used to more accurately reflect the utility's cost of serving participating customers. This helps to reduce the risk of the utility collecting revenues less than its revenue requirement. And if time-based prices are also applied to customer-owned generation, distributed PV will be valued more accurately, and the potential for cross-subsidization will be diminished.

5.3.4.2 Limits and Downsides

Time-based pricing strikes a balance between being accurate and being understandable for the customer. Large customers typically have greater tolerance for complex rates than residential customers.

Time-based rates are sometimes mandatory for industrial and commercial customers but are almost never mandatory and often not available at all for residential customers.[15] Where time-based rates are available to residential customers, it is typical to give customers an opportunity to opt-in. This frustrates time-based pricing advocates because they believe most customers will not take the affirmative action that is required to opt-in, even if it might reduce their bills. Others,

[15] Ontario is the only jurisdiction in North America known to the authors to have mandatory time-based pricing for all residential customers.

however, want customers potentially vulnerable to the results of time-based pricing to affirmatively opt-in due to unexpected outcomes of increased electricity bills.

5.3.4.3 Utility Type

Vertically integrated utilities that can use responsive customers to optimize their generating fleets are in the best position to encourage TOU rates. Under retail competition, the utility might only have control of the delivery charge, a minority share of the bill, to apply these strategies. Circumstances such as winter-summer characteristics, deployment of smart meters, customer tolerance for rate variation, and other factors are important to whether time-based pricing can take hold and make a difference.

5.3.5 Two-Way Rates

The next category of rate design option assumes particular importance as the amount of customer-sited generation increases. Rates can reflect the value for services provided by the grid to consumers and the value provided by consumers to the grid. New rate designs can reflect the emerging reality that the grid is accommodating power flows in two directions. A two-way or "bi-directional" rate tariff clarifies for the customer and the utility what services are being sold in each direction and what will be paid for them. This section presents two types of bi-directional rate designs: value of solar rates and disaggregated rates.

5.3.5.1 Value of Solar Rates

A value of solar rate is one particular type of two-way rate that provides uniform compensation to PV system owners for all of the PV generation they produce. Customers continue to pay for all the energy they consume at the utility retail rate and are compensated by the utility for all of the solar generation their system produces. Value of solar rates differs from net metering, in that the compensation for excess generation is no different than that for generation consumed on-site. It differs from most feed-in tariffs in that the prices offered through feed-in tariffs are most commonly established based on an analysis of customer costs, or through a competitive procurement process, rather than through an assessment of the value of customer generation to the utility system.

The value of solar rate is determined by evaluating the benefit that the PV generation provides to the system. This generally includes the value of line loss savings and energy savings, among other benefits, minus appropriate costs. One advantage of this approach is that it bases the compensation to PV generators on specific benefits and costs of PV within a particular utility system, rather than just the fixed retail rate, as in the case of net metering (Rabago et al. 2012). This can be beneficial as the value of solar to the utility system can change over time; for example, the capacity value (the ability for solar to contribute to system peaks) may decline with higher penetrations (Mills and Wiser 2012).

There are limits and downsides to the value of solar approach. It can slow the deployment of distributed PV if the value raises the payback period and offers a price less than the price offered under a policy it replaces (e.g., net metering). On the other hand, a value of solar tariff could result in prices for distributed PV generation that are higher than previously offered prices and promote greater deployment, while addressing cross subsidies.

Another disadvantage of this approach is that determining the appropriate methodology and compensation rate can be contentious. For example, CPS Energy (the municipal utility of San Antonio, Texas) came out with a proposal for a new "SunCredit" rate of $0.056/kWh to replace net metering (averaging $0.09/kWh). The new rate proposal faced backlash by the solar industry, which insisted that CPS Energy got the valuation wrong. CPS Energy decided to delay the changes and work with the solar installer community to find an equitable solution (CPS Energy 2013).

Any approach that relies on an annual calculation to determine customer compensation will also create uncertainty about future revenue streams for PV system owners, which could make it more challenging to assess project economics and obtain financing. In particular, third-party PV developers argue that unpredictable prices make it exceedingly difficult to raise the large amounts of capital they need to finance thousands of individual PV projects. They assert that value of solar rates (and other feed-in tariffs) has always been more volatile than the basic utility rates that underlie net metering tariffs, making it harder to guarantee investors that projects will pay off.

One additional concern that has been raised about a value of solar tariff is whether it would have implications on the ability of system owners to receive the ITC. Guidance from the IRS indicates that the customer must utilize more than 80% of the generation in order to be eligible for the ITC. Under a buy-all, sell-all structure, the Alliance for Solar Choice (TASC) argues that the customer would not meet the 80% threshold (TASK 2013). However, Austin Energy's value of solar tariff specifies that the customer is not selling all output, but rather receiving a bill credit for the output (Rabago 2013).

Case Study: Austin Energy and Minnesota

In October 2012, Austin Energy began offering a solar tariff that provides $0.128/kWh for all of the generation from participating PV systems in the utility's service territory. The value calculation includes utility transmission line loss savings, energy savings, generation capacity savings, the fuel price hedge value, T&D capacity savings, and environmental benefits. The value of solar rate will be adjusted annually and will vary based on Texas' nodal prices and other factors. The utility's calculations show that the value of solar rate ranged from $0.103/kWh to $0.164/kWh for 2006 through 2011 (Austin Energy 2012).

Minnesota is also considering a value of solar approach. Minnesota's House File 956, signed into law in May 2013, provides a process to determine a value of solar tariff that can then be offered by public utilities in the state. The tariff is designed to compensate customers with PV through a bill credit for the value to the utility, its customers, and society. The Department of Commerce is charged with developing a methodology that accounts for the value of energy and its delivery, generation and transmission capacity, T&D line losses, and environmental value. After that, public utilities in Minnesota can apply to the public utilities commission to offer a solar tariff (Minnesota State Legislature 2013).

5.3.5.2 Disaggregated Rates

Disaggregated rates feature a two-way rate design in which all services provided to and from the utility are valued individually. A value is assigned to each distinguishable element of service that the utility provides to the customer or that the customer may provide to the grid. These services could include: energy, capacity, voltage support, back-up power, and other ancillary services. The disaggregated rate differs from the value of solar rate design because it is applied to every utility customer, not just distributed generators.

This rate structure is in line with the utility services business model, discussed in the business model section in Section 3. It ensures that customers that use a particular utility service pay for the value (the complete costs) of that service. Customers that do not use the service are not required to pay for it. Likewise, distributed generation owners are appropriately compensated for the services they provide to the grid. San Diego Gas & Electric (SDG&E) is developing a model along these lines, but due to its relatively recent inception, performance data is insufficient to discuss program performance.[16]

This approach sends more accurate price signals to customers and third-party project developers than bundled two-way rates, including the value of solar method. Disaggregated rates highlight the elements of distributed PV that bring the highest value to the utility system and compensate customers for that value.

Disaggregated rates will be complex to design and administer, and additional research may be needed to assist in the valuation and rate design. Demonstrations of this concept will reveal how well customers react to this rate option and how well it addresses issues peculiar to distributed PV.

5.3.6 Minimum Monthly Billing

Another option regulators might consider would be to add a minimum monthly payment to an existing tariff structure to ensure at least partial recovery of the fixed costs of serving customers with distributed PV. Under this approach, the customer would pay the monthly minimum and thus contribute some minimum amount to the utility's fixed costs.

5.3.7 A New Customer Class for PV Customers

Regulators may come to see PV customers as distinct from other customers and sufficiently numerous to merit a distinct customer class. Under this approach, distinctions could be made for customers that buy less than some threshold amount of power from the utility. Creating separate customer classes for residential and commercial PV customers would allow regulators to assess the distinct costs and benefits associated with serving (and being served by) these customers and create rates. Wholly distinct rate designs suitable to PV customers could tend to fairly balance the interests of PV customers with the balance of utility customers and may be important for scaling distributed PV to wide deployment. Creating rates for a PV-generating customer class would likely address the question of how a customer principally buying connecting service from the utility should pay for that service.

5.4 Other Regulatory Tools for Removing Utility Disincentives

Even if regulators design perfect rates to compensate owners of distributed PV systems for the system benefits and costs of their output, as PV deployment increases, utilities and

[16] See more about the *San Diego Customer-Owned Distributed PV Impact Study* at http://www.sandiego.edu/documents/climate/SDSolarWorkshop6Presentation20130329.pdf.

regulators will see decreases to the volumetric sales they would otherwise expect. So long as the shareholders of IOUs make their profits entirely or mostly through volumetric rates, IOUs will have an inherent disincentive to support greater PV deployment. Some of the rate designs described above can partially or completely address this throughput incentive by shifting the recovery of fixed costs (potentially including shareholder returns) from the volumetric portion of customer bills to a fixed charge (e.g., the monthly customer charge or a demand charge). But in addition to these kinds of rate design options, regulators can use tactics such as decoupling or performance incentives to encourage the development of DG. These tactics can address the inherent disincentives for utilities to support expanded investment in DG when utility revenues are based primarily on volumetric rates.

Municipal and cooperative utilities do not have shareholders in the way IOUs do, but they are equally sensitive to fixed cost recovery, and some have requirements from their owners or bondholders to make a margin on their sales. This discussion applies to them, but we will not explicitly address here specific adaptations for them that might be appropriate.

5.4.1 Decoupling

Distributed PV reduces conventional sales of electricity by utilities. Decoupling is designed to neutralize the significant incentive that utilities encounter in traditional regulation to increase sales and to resist policies that diminish sales. This incentive is generally called the “throughput incentive.” Absent the throughput incentive, utilities are arguably freer to support societally beneficial policies and tactics that would reduce sales (energy efficiency, DG).

The term “decoupling” can be used in confusing ways. In this report, decoupling refers to a time-limited regulatory device that addresses “revenue adequacy” of the utility as determined in a recent rate case and adjusted by factors built into the decoupling plan at the beginning and that periodically reconciles rates consistent with revenue adequacy. The time limitation is to assure that the structure maintains some temporal contact to a real cost of service; after a long enough time, a re-calibration of the full cost of service with rate levels will keep the decoupling accurate. Decoupling has the effect of leaving rate design unaffected while addressing the throughput incentive, allowing rate design to be used solely to send price signals to consumers. A well-functioning decoupling mechanism will produce rates that approximate what frequent rate cases over the same period would have produced.

As a strategy, decoupling can be implemented in various forms. It generally has periodic reconciliations of the rate based on whether sales are exceeding or lagging a forecast, thereby causing the utility to over- or under-recover its revenue requirements. There are a number of elements or decision points with regard to the design of the decoupling mechanism that regulators can employ to customize decoupling for the policy objectives of their states. For example, a regulator may choose to put a cap on the amount by which rates can be adjusted upward or downward in order to minimize rate impacts. Other considerations include how to allocate refunds or surcharges, whether and how to adjust the authorized return on equity to reflect reduced risk to the utility, whether decoupling should apply only to distribution rates, and whether it should apply in the same manner to every customer class.[17]

5.4.1.1 Advantages

Decoupling offers the following advantages to consumers and utilities.

1. Decoupling removes the focus of the utility on sales volume. Utility managers and employees can then focus on other matters of importance to consumers and the public interest.
2. Decoupling does not disrupt the opportunity for consumer advocates to argue that costs should be disallowed in rate cases or that investments were made imprudently.
3. By adjusting rates to the revenue requirements, decoupling guarantees utilities that they will achieve their revenue requirements (assuming no retrospective disallowance for imprudence) and guarantees customers that any over-recovery will flow back to customers rather than be retained by the utility unless explicitly authorized by regulators.
4. Decoupling reduces the enterprise risk of the utility. Sooner or later, this effect on risk should benefit consumers in the form of lower costs of capital than would otherwise be in place.
5. Decoupling offers an efficient platform to adjust rates in response to sales when few other changes in cost have occurred.
6. Decoupling enables the application of a performance regulatory system, as will be discussed later.
7. Decoupling generally has minimal rate impacts and enables the development of lower-cost energy efficiency resources which, overall, will save customers money over the term of a forecast plan.

5.4.1.2 Performance

Decoupling is currently in effect for some or all of the electric utilities in more than a dozen states. In California, decoupling has been a part of the regulatory apparatus for 20 years and appears to support deployment of distributed resources. Elsewhere, decoupling remains in its early stages and relies on the logic of eliminating the throughput incentive to inspire confidence. Experience to date indicates that decoupling adjustments are mostly small, and decoupling mechanisms yield both refunds and surcharges (Morgan 2013).

5.4.1.3 Limits and Downsides

Some consumer groups lack confidence in decoupling because they are concerned about changing the regulatory principle from a utility *opportunity to earn* a return to a *guarantee* of a return. Advocates worry that utilities will receive revenues irrespective of how well they manage their systems. They also worry that rate adjustments will reduce the frequency with which utilities file for a review of their rates, allowing them to recover what may be an inflated revenue

[17] For a more thorough treatment of decoupling, refer to "Revenue Regulation and Decoupling: A Guide to Theory and Application." (2011). Regulatory Assistance Project.

requirement, and that changes that tend to lower rates may not be included in the decoupling process.

Despite its 20-year history, decoupling is generally unfamiliar to the professionals in commissions and utilities, which can discourage a transition from familiar regulatory practice.

Finally, while decoupling can address the utility's throughput incentive and the lost revenues attributable to distributed PV, it does so by shifting the unexpected costs (or benefits) to all customers through increased rates. But if all or most of the adjustments are made through volumetric rates, this will once again raise concerns about cross subsidies.

5.4.1.4 Utility Type

Decoupling can apply to any utility. It may be more important, however, in cases where the utility recovers a higher-than-average proportion of its fixed costs through volumetric rates or in cases where fixed costs represent a higher-than-average proportion of the total revenue requirement. This is often the case for a utility in retail competition with no generation ownership. Decoupling per se has not been applied to a municipal utility or electric cooperative. The logic is that, in a majority of cases, the managers of those types of utilities can adjust rates as needed and do not need an automatic reconciliation mechanism. However, the purpose of decoupling still applies: the elected managers of these utilities want to avoid the effort and controversy of a full-blown review of rates every time sales (driving revenues) are not as forecast, especially if the utility's underlying costs are not changing much.

5.4.2 Performance Incentives

Performance incentives sometimes attract the focus of utility managers. As with decoupling, performance incentives are not a rate design option but rather a strategy designed to motivate superior performance. They are a regulatory option that can make a difference in the utility attitude toward PV deployment.

5.4.2.1 Quantity

Performance incentives can motivate scale. When used with energy efficiency, performance incentives can promote innovation to produce savings beyond compliance levels. This tool has also been used to motivate improved service quality and reliability.

5.4.2.2 Quality (Location, Process, Societal Factors)

Increased use of performance incentives could work best accompanied by increased attention to setting priorities and performance standards that stretch utility performance. A portfolio of performance metrics could include those associated with deployment of DG and other demand-side options, such as: average days to process interconnection requests, quantity of distributed PV units, and total installed kilowatts. In addition, if installed PV is associated with a goal to reduce power system emissions, regulators could set an emissions performance standard (tons of pollutant/MWh delivered) to reward over-compliance with Clean Air Act standards. Another standard that could be related to deployment of distributed PV would apply to distribution line losses. A standard that rewards the utility for line losses below a certain level could stimulate solutions, including distributed PV in high line loss areas. The process of developing performance metrics could also be useful for a state regulator looking to engage stakeholders in deciding on the most important utility activities and what good performance looks like.

5.4.2.3 Performance

In practice, the amount of potential earnings associated with performance incentives has been a relatively small fraction of total potential earnings. Increasing this fraction can amplify attention surrounding public interest performance indicators and diminish the influence on returns based on investment in assets. Allowing for performance-driven earning outcomes that can either exceed or fall short of the *status quo* can also promote public-interest-oriented performance. Performance incentives are often combined with decoupling. Concerns for the utility include recovering lost revenues and the ability to earn an incentive or return for their customers. Decoupling covers the revenue requirement concern whereas a performance incentive provides the opportunity for utilities to earn a profit for its shareholders.

5.4.2.4 Limits and Downsides

Some stakeholders may question whether utility shareholders deserve incentive payments for an activity for which they did not put their own capital at risk. In addition, providing incentives for routine performance will eventually be considered as wasteful. Setting incentives to the right level will be challenging. It is likely to be an iterative process, with performance metrics and incentive levels closely reviewed until the regulators, the utility, and the stakeholders become comfortable with the level of effort needed to earn them.

5.4.2.5 Penalties

Discussions about performance standards often include debate about whether to include penalties for performance below a threshold of acceptability. Consumer advocates point to the fairness in symmetry while utilities note that events potentially outside their control can skew the results and that the explicit threat of penalties can be a distraction.[18] In balancing these concerns and imposing penalties, the job of regulators will be to determine the cause of poor performance and whether it was due to utility management or events outside their control.

5.4.2.6 Utility Type

Performance incentives have the most impact on IOUs, although they can also apply to municipal and cooperative utilities. An important design consideration is choosing metrics that utilities can control to incentivize performance. Because customers pay the performance incentives, they should also benefit through the level of utility performance. The idea of "value for money" is critical to making performance incentives more than just icing on a cake. A perceived utility "death spiral" may be addressed by using performance incentives to restore some utility earning potential associated with serving customers.

5.5 Other Regulatory Options for Providing Value to Distributed PV Customers

Regulators, on their own or guided by clear legislative language, oversee preferential acquisition of qualifying renewable power or create a market for the renewable attributes of that power. In

[18] Regulators can always penalize a company for poor performance through a reduction in allowed return.

some states with RPS policies, a market for tradable RECs has been created, and through those markets a tangible economic value has been established for each megawatt-hour of electricity generated from qualifying renewable resources. In many DG tariffs, the utility explicitly acquires the right to any RECs that might be associated with that generation, and the value of the RECs is (or could be) a consideration in determining the price paid to the generator.

However, this is not always the case. If the tariff is unclear on ownership of RECs, or if ownership is clearly assigned to the generator, regulators may be able to create tangible economic value for generators through other regulatory means. The State of Ohio, for example, as part of a settlement, required utilities to purchase RECs from distributed PV customers at market prices, but this is done through a REC purchase agreement that is separate from the customer's tariff for electric service.

5.6 Additional Considerations for Regulators

Barring any changes to federal law and FERC regulations, nearly all distributed PV systems will be eligible to self-certify as PURPA-qualifying facilities and, should they do so, utilities will continue to be obligated to offer to purchase those systems' output at rates that are just and reasonable. The exact terms of those rates, considered in the context of other regulatory policies and other options that may be available to customers, will strongly influence the rate of deployment of distributed PV.

Traditional ratemaking principles, such as those published by Bonbright in 1961, can serve as benchmarks for designing just and reasonable rates. However, it is increasingly recognized that distributed PV could raise particular challenges for ratemaking as deployment levels grow, especially if most of a utility's revenue requirement is collected through volumetric rates. Customers with distributed PV will continue to use the utility's distribution system to buy and sell energy, but the utility will sell less energy and collect less revenue from those customers. Rates and regulatory policies will need to ensure that the utility can cover its revenue requirement and continue to safely and reliably provide vital services to all customers. Fairness will be a key challenge. Rates for distributed PV customers would ideally be designed in such a way that those customers reap all of the benefits that they provide to the utility system and pay all of the costs that they impose on the system.

Virtually all industry forecasts predict that the costs of installing PV will continue to decline to levels close to, or even below, retail rates. The impetus for customers to consider distributed PV will only get stronger. Regulators will face the challenge of how best to accommodate this potential growth while adhering to sound ratemaking principles. Several rate design options that more carefully consider both the system costs and system benefits of distributed PV have been presented here; they can be considered alone or in combination. In addition, decoupling and performance incentives can at least partially address the potentially negative impacts of distributed PV on utility motivation and shareholder value.

6 Summary and Conclusions

As interest in distributed PV expands, regulators are challenged with enabling distributed PV deployment, ensuring recovery of utility system costs, and equitably distributing those costs among system users. Decisions made with respect to distributed PV ideally balance the utilities' ability to operate the grid reliably and earn a reasonable return, with customers' desire for choice and the societal benefits of expanding the use of solar generation. In order to maintain equity, the solutions chosen ideally would ensure that the burden of providing for the revenue requirements does not disproportionately fall on those customers who choose not to, or cannot afford to install distributed PV.

Under traditional business models, adding distributed PV to a utility's electric system decreases utility energy sales. At the same time, the investments that utilities are required to make in infrastructure and other generation sources may either increase or decrease. Regulatory treatments and rate designs may or may not reflect the value of service provided to customers. To the extent that rate designs fail to capture the fair value of services provided by utilities and by distributed PV generators, they will lead to non-optimal investment in distributed PV.

6.1 PV Costs and Benefits

As the amount of distributed PV on utility systems increases, regulators face a new challenge of understanding the benefits and costs of distributed PV. Currently, there is little consensus about the value of these benefits and costs, and quantifications vary substantially based on local conditions and the methodology employed.

Regulators may seek to develop screening criteria to determine the benefit/cost ratios of distributed PV under different scenarios. Screening results can be used to evaluate the regulatory treatment of distributed PV generation and utility business models for facilitating distributed PV installations. Criteria can also be used to assess various rate design options to identify those that are most equitable and encourage distributed PV installations in high-value locations. In some cases, the screening criteria that are most commonly used for energy efficiency may be applicable, in adapted form. These include the total resource cost test, the societal cost test and the utility cost test.

Achieving maximum net benefits from distributed PV requires careful attention to the valuation method employed to quantify the costs and benefits of distributed PV, the criteria used to evaluate distributed PV, the regulatory mechanisms used to support delivery of distributed PV services, and the rate design for conveying price signals to customers, service providers, and utilities.

6.2 Business Models

A wide variety of business models can provide utilities flexibility in terms of their level of direct investment and role in the development of distributed PV. New business models also have the potential to provide customers with more choices that can be tailored to their needs, preferences, and budgets. An important consideration is the appropriate balance between services provided by third parties versus services provided by the utility. Regulators are in a position to influence the balance through the ways in which they encourage or discourage various models for utility participation in distributed solar.

For vertically integrated utilities, some business models can allow recovery of the investment costs for ownership of DG, which could be built into capacity expansion plans. In the process of resource planning, regulators and utilities may wish to consider distributed PV not only as a net load, but as a supply option and a wires option. Using the planning process to identify least cost options to increase system reliability could optimize cost-effectiveness and increase grid reliability through strategic placement of distributed PV.

In restructured markets, utilities can compete to offer distributed solar services. For any competitive utility business enterprise, regulators may wish to consider requiring corporate separation along with a robust code of conduct to ensure a level playing field for the operation of competitive businesses and for the public benefit. These steps can address concerns about market domination and the stifling of competition and innovation that could limit customer options or result in higher rates or inferior product offerings.

6.3 Rate Design and Regulation

Utilities seek to design tariffs that reflect cost-of-service principles, while regulators strive to ensure that the rates in those tariffs are just and reasonable. Some of the key principles that regulators have historically relied upon are that tariffs should: (1) keep the utility viable by yielding the total revenue requirement; (2) fairly apportion the utility's cost of service among consumers; and (3) result in relatively stable rates without unduly discriminating against any customer or group of customers. As penetrations of distributed PV grow, rates and regulatory policies will need to ensure that the utility can collect enough revenue to cover its revenue requirements and continue to safely and reliably provide vital services to all customers. Rates for distributed PV customers would ideally be designed in such a way that those customers reap all of the benefits that they provide to the utility system and pay all of the costs that they impose on the system.

EPACT required state utility regulators to consider (but not necessarily adopt) a net metering standard for customer-owned generation. Nearly all states require some form of net metering for DG, but there is growing debate about whether net metering over-compensates or under-compensates distributed PV customers. Further, federal law requires utilities to offer to purchase the output of most distributed PV systems, but regulators may not force a utility to pay a price that exceeds the utility's avoided costs.

Several alternative rate designs have been proposed as replacements or supplements to net metering. Alternative rate designs include: fixed monthly customer charges; demand charges; stand-by rates; time-based pricing; two-way rates; minimum monthly billing; and creation of a new distributed PV customer class. Each rate design potentially offers distinct advantages and limitations relative to other designs. Some alternative rate designs partially or wholly address the utility's reluctance to support any policy that reduces retail sales to customers (the so-called throughput incentive). To reduce the throughput incentive and motivate the utility, supplemental policies like decoupling or performance incentives could be applied.

Regulators can adapt a variety of tools to address concerns arising with greater reliance on distributed PV. There is unlikely to be a single solution. In fact, regulators may seek to use a combination of tools to address concerns and meet the needs of stakeholders.

6.4 Looking Forward

Distributed PV deployment is unfolding at different rates in jurisdictions across the country. This uneven deployment is likely to continue in future years due to differences in policies, incentive levels, solar resource potential, and electricity rates. Regional variance in deployment, as well as differences in regulatory structures, suggest that regulatory responses will also need to be diverse. These issues are not confined to locations that have already experienced significant distributed PV growth; distributed PV has the potential to expand rapidly across the country, and it is important for regulators to consider possible impacts before substantial deployment occurs.

To enable the creation of equitable solutions in the future, some gaps in knowledge warrant attention. For example, the benefits and costs of distributed PV at higher penetration levels are not fully understood yet; therefore, additional efforts to identify and quantify system effects are needed to ensure equitable solutions. Furthermore, cost-of-service figures and utility financials will change substantially from what they are today if higher penetrations of DG are achieved. Greater understanding of the impacts of potential changes in business models and other financial impacts could help effectively identify and evaluate regulatory options.

7 Questions to Frame the Regulatory Discussion

Policymakers and regulators in each state face the challenge of crafting policy and regulatory responses that fit their respective contexts. Differences in solar insolation, electricity prices, policy priorities, and the regulatory context of states have resulted in different regulatory responses to the development of distributed PV; one size will not fit all going forward. However, many of the questions regulators will need to ask to determine the path forward are similar. The following set of questions is intended to help policymakers and regulators identify pertinent issues, determine feasible options, and make better informed decisions.

1. How much distributed PV adoption does the state expect to experience in the coming decade, given retail electricity rates, incentives, and PV cost trajectories?
    A. Have there been significant changes in the rate of distributed PV deployment in the state over time? What were the main drivers for these changes (e.g., state policy, regulatory changes, industry changes/cost decreases)?
    B. If there is a specific deployment target indicated by state policy, will it likely be met or exceeded? Are there challenges or barriers that need to be addressed to meet current policy goals/targets?
2. How does current and expected deployment compare with that in other states that have similar resource quality and retail electricity prices?
    A. How have other states responded to challenges or barriers in meeting their state targets? Can we learn from their experiences to help us meet our goals at least cost and least risk?
    B. Do the differences in deployment between states indicate relative strengths or weaknesses in our state's approach, or are they indicative of other factors?
    C. What do the experiences from other states indicate about the best way to prepare a state and its utilities for the higher penetration levels? Are the utilities in our state well positioned to accommodate higher PV penetration levels if state or federal policy or economics drive significant increases beyond projected levels?
3. Are the state's utilities positioned to undertake infrastructure upgrades that may be necessary to accommodate higher levels of distributed PV?
    A. Under what conditions and at what deployment levels might additional system upgrades be required to accommodate distributed PV?
    B. Under current regulatory mechanisms, who is responsible for paying for necessary upgrades?
    C. Is the responsible party and cost recovery mechanism clearly defined for all foreseen scenarios?
4. Are the state's utilities positioned to capture the potential benefits of intentionally locating distributed PV at specific locations on the utility system?
    A. Is the expected distributed PV deployment clustered in one or more areas of the grid? What are the implications of this clustering to the system, the utilities and the customers?

B. Can PV be strategically located on the system to optimize the T&D system benefits? What would be the financial savings of doing so?

C. Is it appropriate to consider policies that would encourage the location of distributed PV at specific locations? If so, what signals can be used to encourage the strategic placement of distributed PV in locations that maximize the benefits?

5. Given the expected penetration levels, how will distributed PV affect each stakeholder group?

A. What are the key benefits of distributed PV from a utility perspective? What are the key costs?

B. What are the key benefits from the perspective of a customer with and without distributed solar? What are the key costs?

C. How are distributed solar customers and non-participating customers affected by current policy and rate structures?

D. What role will the various stakeholders (including utility and third-party providers) play in the development of distributed PV if the current environment persists? What is the desired role?

E. Are there risks being borne by utility ratepayers that would be more appropriately proportioned to third-party providers or other stakeholders?

F. How can the benefits and costs of distributed PV be appropriately proportioned to all stakeholders?

6. Are stranded assets a possibility?

A. What opportunities are there for distributed resources to reduce or delay the costs of system upgrades?

B. What are the financial risks of making T&D infrastructure and generation investments today if penetrations of distributed systems are higher than expected?

C. How can these risks of incurring stranded assets be minimized?

D. How can the value of the utility grid (or the value lost by disconnecting from the grid) be quantified?

E. What are the impacts of higher distributed PV adoption on utility financial health if no changes in the utility business model, regulatory treatment or rate design are implemented? How much will expected penetrations of distributed PV affect system fixed costs, utility revenues, and customer bills?

F. What financial metrics should we track to monitor the financial health of our utility?

G. From a financial perspective, at what level of distributed PV penetration will the utility have difficulty ensuring system reliability?

7. Are there opportunities to learn from past policy experiences with respect to rate design, utility compensation, third-party providers, and impacts on non-participants?

A. What lessons can be learned from other states or countries?

B. What lessons can be learned from the experience of the telecommunications industry?

C. What parallels are there with respect to the adoption of other new technologies that give consumers alternatives to traditional service?

8. Is the state policy and regulatory model one that facilitates retail competition and consumer choice? If so, how can the utility system be maintained while facilitating customer choice (i.e., for options such as distributed PV), enabling competition, and keeping electricity affordable?

9. Regardless of whether the state is tending toward more restructuring or trending toward more traditional regulation, the question will remain: How are customers who choose to retain traditional, integrated service affected by higher penetrations of PV?

10. How can the need for the utilities to meet their revenue requirements be balanced with the societal goal of promoting PV and assuring that nonparticipating customers are not unduly burdened with rate responsibility?

11. Regardless of whether one is tending toward more restructuring or toward more traditional regulation the question will remain: What are the costs and benefits of distributed PV for different stakeholders?

    A. What benefits and costs of distributed PV are our state counting as accruing to participating solar customers and non-participating customers? What are the benefits/costs to broader society? To the utilities?

    B. What are the key gaps in the state of knowledge regarding the costs and benefits of distributed PV on the system?

    C. What data or resources are available to help fill these knowledge gaps so that our state can ensure the appropriate sources of costs and benefits are included as we evaluate the impact of policies and regulatory treatments?

12. Is the state policy and regulatory model of the future one of modified rate of return regulation with limited retail competition and consumer choice? If so, what combination of rate tools and rate designs are needed to facilitate PV choice and cover fixed system costs in our state?

    A. What rate structures address revenue issues without encouraging PV customers to flee the grid?

    B. What are the pros and cons of establishing tariffs based on fixed charges, demand charges, or minimum monthly bills? What are the equity issues of applying fixed or demand charges or minimum monthly bills to distributed solar customers only, as compared to all ratepayers?

    C. What would be the implications of applying fixed charges, demand charges, or minimum monthly bills on the effectiveness of energy efficiency programs?

    D. How should the utility's role as "the provider of last resort" be accounted for in rates?

E. What are the impacts of disaggregated rates and value of solar tariffs on customer equity, utility revenues, and grid security/reliability? What types of information and analyses are needed to develop a disaggregated rate, or a value of solar tariff?

13. What are the barriers to the adoption of new utility business models? What regulatory changes need to occur to facilitate the development of new utility business models?

    A. What business models best ensure recovery of system costs and equitability among ratepayers?

    B. Which business models are best suited to regulated utilities?

    C. What are the regulatory obstacles to the implementation of a business model in which utilities function as grid services providers, without necessarily engaging in power supply (e.g., energy services utility)? What aspects of this model are desirable, from a regulatory standpoint? What aspects are less desirable?

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Section 3

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